ATTACHMENT 1

Business Case Summaries and Supporting Information

1.0 Business Case Summaries ("BCS")

Attached is a listing of all capital projects with a Total Project Cost (actual or forecast) of $10M or greater, and their associated BCS (excluding P2/P3 Isolation Project, see Ex. D2-T1-S1, section 4.0). Paper copies of the business case summaries are provided in a separate binder (EB-2008-0008 Volume 4)

Note: Several attachments are marked "Confidential" because the original documents contain confidential information. The redacted versions provided as pre-filed evidence are not confidential.

2.0 Security Project Description and Need

This section provides a brief project description of the security-classified nuclear projects, for which BCS are not provided. This level of information is the same as that submitted in EB-2007-0905.

In all cases, the need is the requirement to meet Canadian Nuclear Safety Commission ("CNSC") security requirements, which are common to all OPG nuclear stations (Pickering A, Pickering B and Darlington).

- <u>Project 25609, Physical Barrier System</u> (was Security Fence Project): Install improved perimeter fencing system at Pickering A, Pickering B and Darlington, including lighting, perimeter monitoring and other required functions.
- <u>Project 25902, Controlled Area Improvements</u>: Reconfigure site access, such that all access to the Pickering or Darlington sites is through a single secure entrance.
- <u>Project 25905, Security Monitoring Room</u>: Replace security monitoring rooms at Pickering site and Darlington to meet current requirements.
- <u>Project 25901, Security Hardening Project</u>
- <u>Project 25908, Security Doors Upgrade</u>
- <u>Project 62558, Security Optimization:</u> Improve physical security provisions within Pickering A, Pickering B and Darlington stations.

Nuclear Business Case Summary Index

Tab	Facility	Ongoing Projects From EB-2007-0905	Project No.
1	DN	DLC Modifications – Simulator Based Training	28453
2	DN	Fuel Handling Power Track Modifications	31438
3	DN	Improve Maintenance Facilities	31717
4	DN	New Change Room Facility	31718
5	DN	Chiller Replacement to Reduce CFC Emissions	33631
6	DN	FH Computer Replacement	33815
7	DN	SDS Computers Aging Management	33955
8	DN	SG Controls Replacement	33973
9	DN	DCC Replacement/Refurbishment/Upgrades	33977
10	PA	Calandria Vault Inspections	46537
11	PA	D_2O Storage Tank Project	46576
12	PA	Unit 1 & 4 Calandria Vault Dryer Augmentation	49252
13	PA	Switchyard Relay Building Cable Replacement	49266
14	PB	Emergency Power Generator Control Upgrade	49110
15	PB	Chemistry Standards (CH-002)	79147
		Completed/Deferred From EB-2007-0905	
16	DN	Second Darlington Full Scope Simulator	28452
17	DN	D_2O Storage Facility	31555
18	DN	Main Control Room HVAC	33293
19	DN	Used Fuel Dry Storage in Station Modifications	33925
20	DN	Auxiliary Heating System	34000
21	DN	Feeder Replacement ALARA	34008
22	DN	Fire Protection Upgrade Program Phase 3	79148
23	PA	D_2O Storage Facility	49251
24	PB	CFC Replacement (Freon Removal)	40543
25	PB	Auxiliary Power System	49104
26	PB	Standby Generator Governor Update	49109
27	PB	Fire Protection Phase 2	79016
28	ENG	Additional Feeder Cut and Weld Tooling	62567
		Projects Not In EB-2007-0905	
29	DN	Vacuum Building Outage Recurring Alterations	34012
30	PA	Replacement of Standby Boiler	49267
31	PA	Inter Station Transfer Bus Capacity Increase	49270
32	ENG	Feeder Repair by Weld Overlay	62568
33	IMS	Upper Feeder Cabinet Inspection Robot	66266

Second Darlington Full Scope Simulator Project 16 - 28452 Capital 16 - 28453 Capital

Full Release Business Case Summary D-BCS-59000-10002-R000

1/ RECOMMENDATION:

We recommend approval of a Full Release of $28.0 M Capital (including contingency) to complete the remaining phases of the Second Darlington Full Scope Simulator and the Darlington Learning Center Modifications Projects, with the objective of having a second full scope simulator available for training in Q3 2009. This includes U2 and U0 panels and the modification of the existing DLC to accommodate the simulator and supporting training facilities including upgrades/installation of HVAC, Fire Protection, electrical, LAN, telephone, PA, structural, training classrooms, conference/maintenance rooms, restroom facilities etc. The existing training simulator for Darlington Nuclear Generating Station cannot support Operations simulator needs. Simulator needs have increased beyond the hours available from a single simulator. There are 4 primary business objectives for this project:

1) The business objective is to address the high attrition rates for current DNGS certified staff. It is forecasted that 18 Authorized Nuclear Operators (ANOs) are eligible for retirement in the current business planning period and it is a requirement to assume 100% attrition as per the commitment to the CNSC (Attachment E: Correspondence from T. N. Mitchell, CNO, to G. R. Schwarz and T. E. Schaubel, CNSC. N-CORR-00531-03850.) Based on the staffing plans and current assumptions, without the second simulator, the sustainable ANO staffing levels of 56 required to run the business will not be accomplished within the current Business Planning Cycle.

2) The business objective is to support increased planned and minimum complements on each shift crew. DNGD has an more stringent licensing requirement to ensure only certified staff are on the MCR panel at all times, which means that the use of Supervised Control Panel Operators (uncertified staff) will no longer be allowed. Originally the license requirement was a minimum complement of 4 ANOs, and in 2005 the license minimum complement increased to 5 ANOs. By July 2009 the license minimum complement will increase to 6 ANOs. This factor will increase the demand on simulator hands-on hours. The REG-C N-CORR-00531-03217 compliance date is July 31, 2009. In order to ensure that there are 6 ANOs on duty at all times, 40 ANOs need to be assigned to the 5 operating crews and an additional 16 ANOs for other supporting roles is required to be self sustaining (See Attachment D).

3) The business objective is to ensure the safe and effective operation of the station to support not only the licensed positions on shift but also the supporting roles in areas of: outage planning, integrated planning, continuing and initial training, fix it now teams etc. To not staff and support these roles will result in a significant and adverse affect on the Stations Operating and Outage performance as well as challenge the safe operation of the station.

4) The business objective is to increase continuing training hands-on hours per year for certified staff to the recommended industry minimum standard and, thereby, meet CNSC expectations for authorized personnel training and eventually reach top industry standards. The CNSC references governing documents issued by INPO as their guideline to improve performance at Canadian Nuclear Plants. The Academy Document produced by the National Academy for Nuclear Training (NANT) under the support of INPO, "Guidelines for Continuing Training and Recertification of Licensed Personnel, January 2007, ACAD 07-001", states that the minimum number of technical content contact hours per year is 160 (200 on average), which includes 60 hours of hands-on simulator training. OPG has committed to the CNSC to follow this requirement and meet 200 hours of simulator focused continuing training hours per year (Attachment F: Correspondence from G. Preston, Executive VP & CNO to G. Schwarz, Dr. Personal Qualification Assessment Division CNSC, N-CORR-00531-00948, Sept. 29, 2000). DNGS is currently at 200 hours for simulator focused continuing training per year for certified staff, with only 30-35 hours being simulator hands-on time. 60 hours of hands-on time is considered a minimum (ACAD Standard) and in fact the majority of other utilities are training on average approximately 95 hours per year (See graph C in the Background and Issues Section).

Training projections are outlined in a "Two Simulator Rationale" (Attachment G) document prepared by the Training Department that estimated Simulator loading based on approved 2005 - 2009 staffing plans and training program documentation as well as an estimated numbers of hours required to meet industry standards. The results were verified though an external third party review and the risks were assessed by performing a sensitivity analysis.

[illegible]e objective will be achieved by the addition of a second full scope simulator and supporting facilities at the Darlington Learning Centre (DLC). Initial training programs will continue at the existing simulator located in the Pickering Learning Centre (PLC) with all continuing/re-certification training performed at the DLC. This strategy will ensure that adequate time is available to handle the increased demands for training, delivery and testing.

Anticipated licensed staffing requirements to support the upcoming REG-C N-CORR-00531-03217 compliance date of July

2009, has been considered and included in the Future Business Planning Cycle. Related OM&A costs to maintain the new simulator and DLC facilities are described in Appendix C under Financial Model Other Assumptions.

$000's (Incl contingency)	Class	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	Capital	Developmental	69	864	-	-	-	-	-	933
Currently Released	OM&A		-	-	-	-	-	-	-	
Requested Now	Capital	Full	-	1,479	18,812	6,104	628			27,023
Requested Now	OM&A		-							
Future Funding Req'd	Capital	None								-
Future Funding Req'd	OM&A									
Total Project Costs			**69**	**2,343**	**18,812**	**6,104**	**628**	-	-	**27,956**
Other Costs										-
Ongoing Costs										-
Grand Total			**69**	**2,343**	**18,812**	**6,104**	**628**	-	-	**27,956**
Investment Type			**Class**		**NPV**		**IRR**		**Discounted Payback**	
Sustaining			**Capital & OM&A**		**44,949**		**16.0%**		**10.2**	

Submitted By:

(for) Bruce Duncan July 18/2007

Wayne Robbins Date:
Sr. Vice President Darlington Nuclear

Finance Approval:

D Power Aug 22/07

Don Power Date:
VP Corporate Investment Planning

Line Approval (Per OAR Element 1.1 Project in Budget):

J Hankinson Aug 23/07

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CEO

BACKGROUND & ISSUES

The training of Authorized Staff including Shift Managers, Control Room Shift Supervisors and Unit Main Control Room Operators is a critical component of Plant Operations. The training and qualification of these staff is time and resource intensive. The standards and regulatory requirements surrounding this area are governed by the regulatory body governing the operation of the plant (CNSC) and best industry practices (INPO and WANO).

The training of the authorized staff can be broken down into three specific areas.

- Initial training (and testing) of personnel to be qualified for certified positions.
- Continuing training programs to maintain the skills and qualification to meet both DNGS and industry standards.
- Recertification testing of authorized staff. This facet of the program is to allow support continued licensing of the authorized individual by the CNSC.

In the late 1990s, an Integrated Improvement Plan (IIP) initiative was developed to consolidate and improve training at the site. Space for a future simulator was included in the construction of the DLC. A project that involved moving the existing Simulator from the PLC to the DLC was approved in 2003 and then subsequently cancelled in early 2004 by the Nuclear Executive Committee prior to the start of any field execution activities (ref. D-BCS-33813-10001). Although it had a number of benefits, this project did not address the cause of many of the training deficiencies – insufficient simulator time.

Later in 2004, a Darlington Authorization Training Focus Group was formed in response to a number of candidates withdrawing from the program (ref. SCR D-2004-05573). The purpose of the group was to evaluate training methods and to explore alternative strategies to achieve the Darlington staffing plan for Authorized Nuclear Operators (ANOs). A number of solutions were put forward (See A/R# 28055593) and have since been implemented to improve the program and increase the success of candidates. These included:

- improving the selection and preparation process for candidates - Complete
- increasing the number of Authorized Training Supervisors (ATSs) – Complete – with rotations from the plant
- improving documentation – Continuing requirement
- provision of desktop simulators for use by ATSs to reduce loading on the full scope simulator - Complete
- split mode operation of the simulator to allow concurrent U0 and reactor unit training - Complete
- development of schedules to allow simulator use from 6:00 a.m. to 12:00 a.m., 7 days a week – Complete. In addition interim training classes are scheduled until 04:00, but are not expected to continue due to Society and PWU agreements.
- increasing class sizes to makeup for loss of candidates - Complete

These initiatives, although expected to improve the short term success of training, have not been sufficient to maintain adequate staffing levels.

Since these initiatives have been implemented several issues have developed that are driving the amount of simulator hands-on time required to meet mandatory training and testing programs above the time available on the current Simulator located at the PLC. High attrition rates, and increases in shift minimum complement both contribute to the increase in simulator hands-on time.

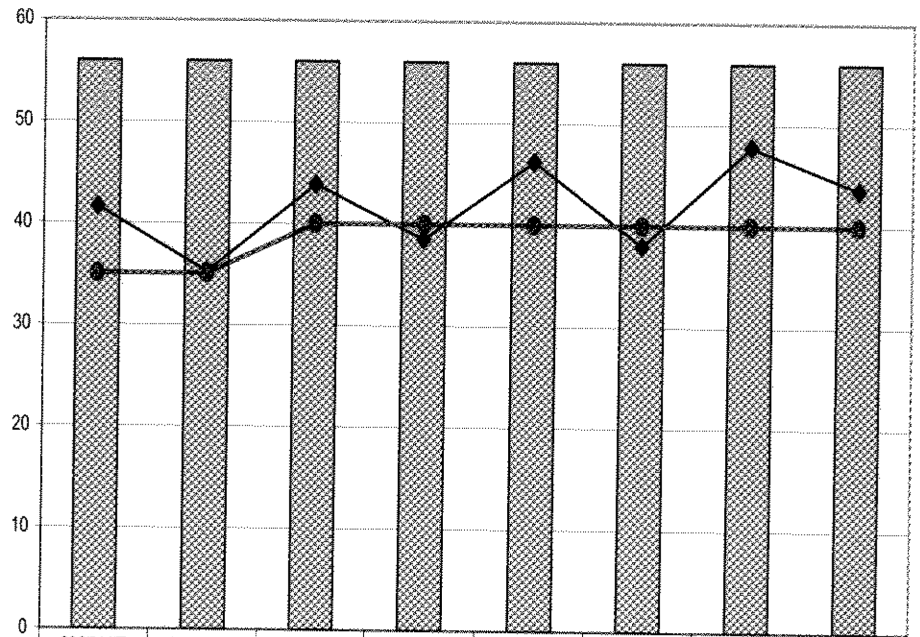
The following charts model the projected staffing scenarios based on both 1 and 2 simulators. Based on the staffing plans and current assumptions, without the second simulator, the sustainable ANO staffing levels of 56 required to run the business will not be accomplished within the current Business Planning Cycle. With this, comes a significant risk for the next 7 to 8 years, as the staffing levels are extremely low. Note, staffing plans since 2005 are based on a 2nd simulator being in full operation by Q1 2009 based on approvals obtained from the NEC.

Graph A: One Simulator Only

Assumptions & Notes

- ANO retirement is 100% uptake within one year of achieving an undiscounted pension (N-CORR-00531-03850)
- Only certified ANOs are shown
- 70% success rate on certification program (N-CORR-00531-03850)
- Internal staff movement occurs only to ATS and SSIT positions
- Supply is taken from SAP as of YE 2006 and includes regular staff in their home base assignment
- Retirements of ATS staff will be filled by promotion of ANOs
- Reflects current business plan submissions for 2007

Certified ANOs
Darlington Supply vs. Business Plan Demand

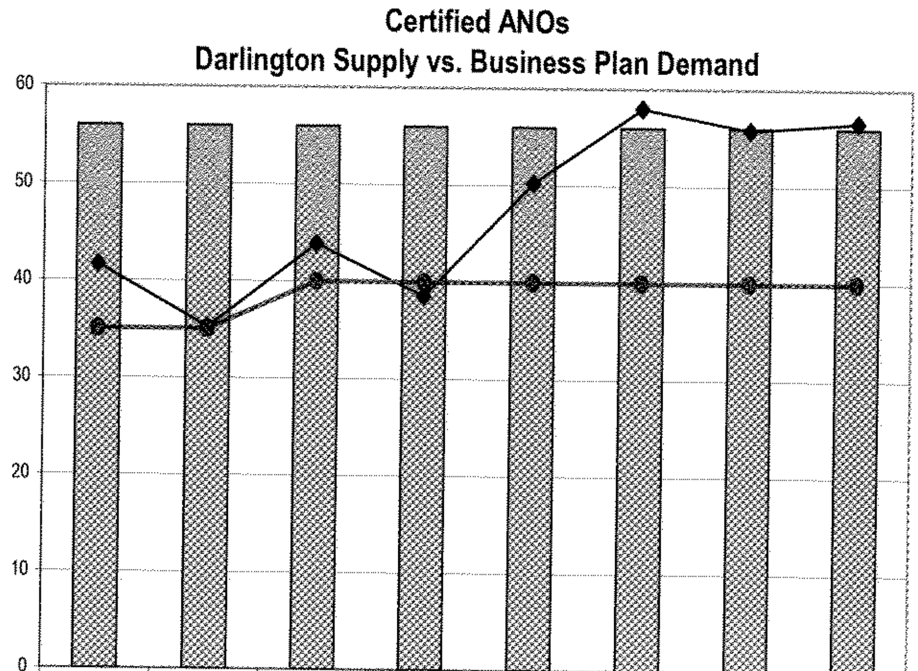


	2007 Y/E	2008 Y/E	2009 Y/E	2010 Y/E	2011 Y/E	2012 Y/E	2013 Y/E	2014 Y/E
Target ANOs - Base positions per Bus plan	56	56	56	56	56	56	56	56
CNSC Commitment - ANOs on shift	35	35	40	40	40	40	40	40
Projected Supply of Certified ANOs	42	35	44	39	46	38	48	44
Projected ANO certifications	8	0	12	0	12	0	12	0
ANOIT Starts	16	0	16	0	16	0	16	0

Graph B: Darlington Second Simulator

Assumptions & Notes

- ANO retirement is 100% uptake within one year of achieving an undiscounted pension (N-CORR-00531-03850)
- Only certified ANOs are shown
- 70% success rate on certification program (N-CORR-00531-03850)
- Internal staff movement occurs only to ATS and SSIT positions
- Supply is taken from SAP as of YE 2006 and includes regular staff in their home base assignment
- Retirements of ATS staff will be filled by promotion of ANOs
- Reflects current business plan submissions for 2007



	2007 Y/E	2008 Y/E	2009 Y/E	2010 Y/E	2011 Y/E	2012 Y/E	2013 Y/E	2014 Y/E
Target ANOs - Base positions per Bus plan	56	56	56	56	56	56	56	56
CNSC Commitment - ANOs on shift	35	35	40	40	40	40	40	40
Projected Supply of Certified ANOs	42	35	44	39	50	58	56	57
Projected ANO certifications	8	0	12	0	16	16	0	5
ANOIT Starts	16	24	0	24	10	0	10	0

Note: Both Graphs A and B above assume that all licensed staff will become recertified each year. Currently each certified ANO receives only 30-35 hours of hands-on time and OPG has committed to the CNSC to follow the requirement of the ACAD 07-001 document as per correspondence from G. Preston, Executive VP & CNO to G. Schwarz, Dr. Personal Qualification Assessment Division CNSC, N-CORR-00531-00948, Sept. 29, 2000 (Attachment F).

The chart in Attachment D (ANO Deployment based on Certified Staff Numbers) describes the risks due to attrition for licensed ANOs.
As stated, once the number of 44 certified ANOs is reached the business will not be able to recover from this without significant impacts to running the units. Prior to this point however, risks to the safe and effective operation of the station are also present as we deviate from the business plan number of 56 ANOs.

The delta between the projected CNSC commitment of ANO's on shift and the target number of ANO's defines the number of ANO positions in the Darlington organization to support the safe operation of the station and the continuation of the initial and continuing training programs. The roles of these positions are defined in the various governances related to Outage Planning and assessing, Integrated planning processes, Fix it now (FIN) team composition and Training programs development and execution. Significant adverse affects on station performance will result should these roles be omitted and the accountabilities not be carried out. The nature of the programs is such that an individual with the training knowledge and skills of an authorized person are required to make these processes effective. The accountabilities range between functional group but include:

- Operations and License review and approval of scheduled and planned maintenance work programs, procedures, and work plans on Nuclear Units in accordance with department governance and procedures.
- Operations and License review of the schedules coordinating work and outage activities.
- Outage Management oversight.
- License review of Reactor Alignment changes during outage and routine planned maintenance activities.

- CNSC mandated continuing training program execution. Development and delivery of training in both initial and continuing training programs.

Another issue contributing to the demand for a second simulator is that DNGS is currently only at 30-35 hours of continuing training simulator hands-on hours. OPG has committed to the CNSC to follow the requirement of the ACAD 07-001 document issued by INPO and deliver 200 hours of simulator focused continuing training, of which 60 hours is simulator hands-on hours.

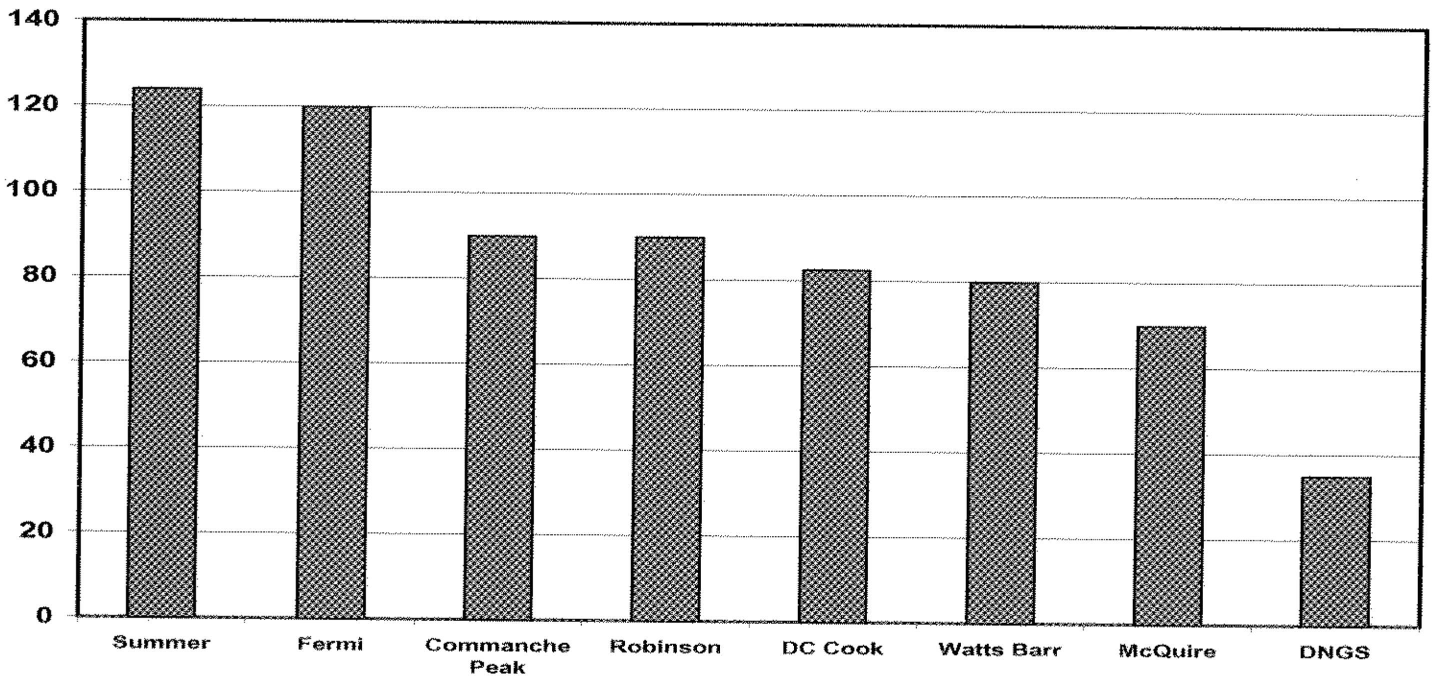
As the experienced operators retire and are replaced by new less experienced license holders, simulator training will be a critical factor in preparing operators to effectively respond to unit transients and prevent them from escalating to more severe events. As operating experience decreases there is a risk of more events occurring due to operator errors. The average experience of Darlington's certified staff is expected to drop over the next couple years. Details can be seen in the chart below:

Table 1: Average Licensed Operator Experience

2005	2006	2007	2010	2012
7	7.7	6.3	6	5

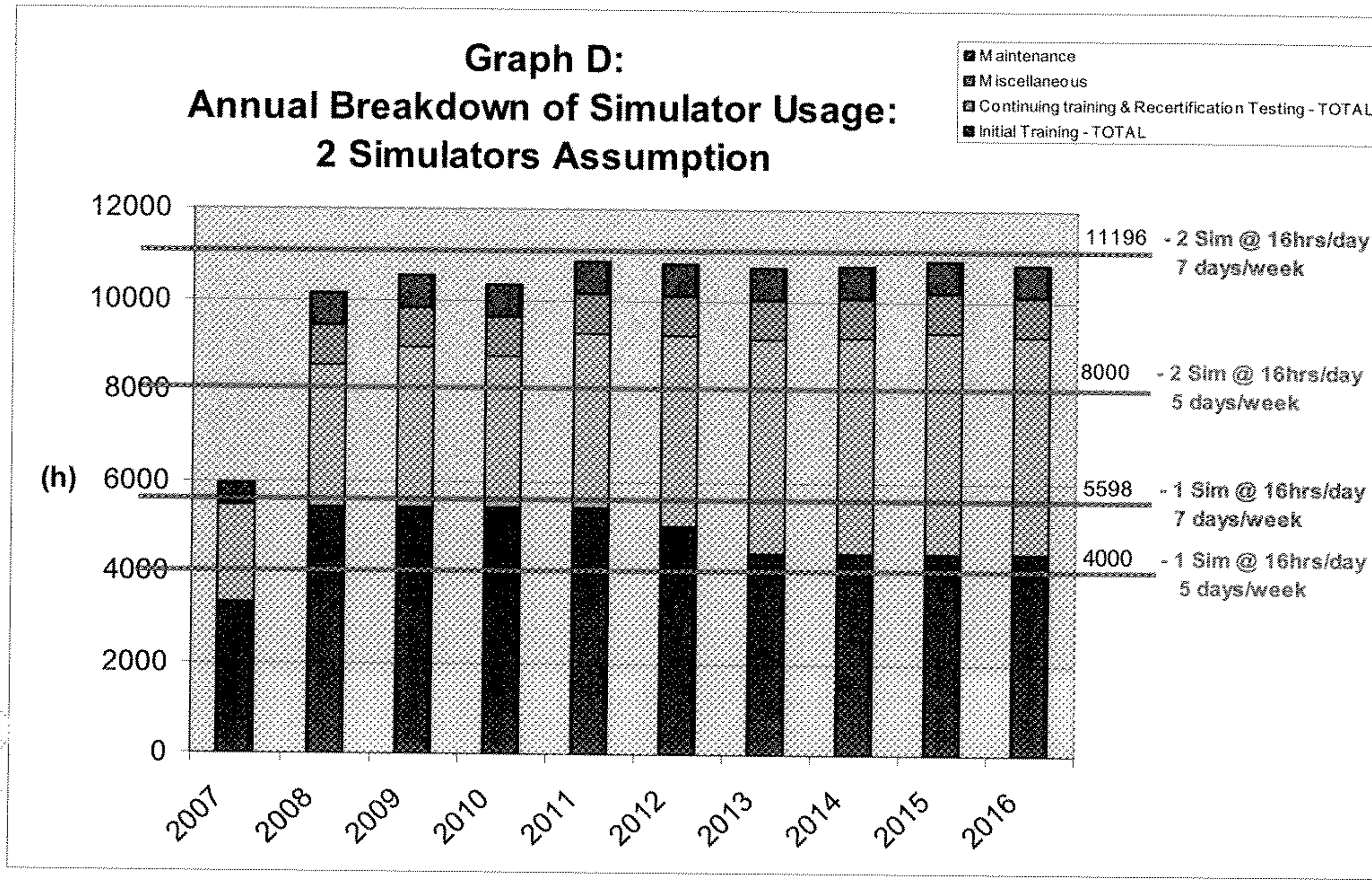
Industry experience has shown that qualified but inexperienced certified staff needs 80 hours of contact time to ensure they maintain the skills and knowledge to respond to transients and events and in fact the majority of other utilities are training on average approximately 95 hours per year.

Graph C: Simulator Hands-on Hours per Year per Operator



Currently, DNGS licensed staff are receiving 30-35 hours of simulator hands-on hours. This does not meet our regulatory commitment, and there is an inherent risk to the safe operation of the plant.

A simulator hands-on demand analysis was performed to determine the total amount of hands-on hours required to maintain the certified staffing plan shown in Graph B above for safe operation.



Assumptions:

- Available Simulator training / testing usage between 08:00 to 24:00 for 5 days a week without weekends and holidays results ~ 4,000 hours of simulator time a year.
  - 365 days -104 days [weekends] – 8 days [holidays] = 253 days -2% breakdown = 3967 hours @ 16 hrs/day.
  - This does not include the 30 days for annual maintenance outage, where 320 hours are lost from training and testing or the regular day to day maintenance where an additional 384 hours are lost over the year.
- For continuing training of currently certified ANOs, to calculate the amount of hands-on time, the number of projected ANOs is divided into groups of 3 and then multiplied by 60 hrs (as only 3 can be credited with actual "hands-on" time per training event). 1/3 of the number of delivery hours is added due to efficiency of simulator usage (set-up time, turnaround, etc.). This has been scaled up/down as applicable in the table for years where the number on ANOs is greater or less than 60.
- All types of training (initial and continuing), all types of testing (initial and recertification) for all types of certified staff (ANOs, U0CROs, CRSSs and SMs) require a large amount of simulator time for both development and delivery (and a smaller component of simulator time for remedials).

As highlighted in the graph, only approximately 4000 simulator hours are available per year for training, testing, maintenance and miscellaneous activities and DNGS needs already far exceed this. Because of CNSC commitments for 2009, the amount of hours required to meet the current Business Planning Cycle for certified staff is more than double.

Actions have been taken to mitigate the hands-on time delta between supply vs. demand. For example, DNGS Operations have tried to retain the current certified staff beyond early eligible retirement date, but this does not eliminate the long term attrition and in the future this option will not be viable due to reluctance from a bargaining position. As well, to accommodate for these extra hours currently in 2007, training is scheduled on midnight shifts and weekends. However, this poses a risk to the safe operation of the nuclear reactors in the future if OPG decides to continue with this option and not proceed with the second simulator. Based on the collective agreement, Letter Of Understanding (Attachment H: LOU - 119) for CRSS CRSOS, ATS, UOTS and SSIT, if overtime cannot be filled on a voluntary basis, forced overtime will be limited to 3 non-consecutive weeks per employee (and is even more restrictive for ANOs, CROs, ANOITs and CROITs in the PWU).

PNGS B is currently not in the same position as DNGD and has not requested the need for a second simulator in the current Business Plan. The current CNO accepted business assumption is that there will not be a refurbishment at PNGS B. In addition, PNGS B currently has a younger demographic and do not require unit zero certifications.

OPEX and planning for a second simulator at Bruce B was investigated. Response to date with regards to Bruce B has been limited due to the sensitivity of information and they have not stated whether they are including the requirement for a second simulator in their current business plan. It was released however, that if the decision to refurbish Bruce B is made, a Full scope second simulator will be included in that Business Case.

Currently Bruce A, and two US three-unit stations, Palo Verde and Browns Ferry, have a second simulator. Oconnee's is pursuing a second simulator (approval pending).

Developmental Release of $933k was obtained in September 2006. The project has completed Preliminary Design for DLC Modifications in May 2007. Completed Technical specification, Request for Proposal, Bid evaluation to Engineer, Procure and Construct a second full scope simulator, and awarded contract in June 2007 to complete Preliminary Engineering for Main Simulator by Oct 2007.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$000's	No Project	Alt 1 (Recommended)		Alt 2	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost	Delay 1 Year			PLC Option
Revenue	(360,337)	0	0	(11,868)	0	0	4,772
OM&A	(94,054)	(109,514)	(109,514)	(107,547)	0	0	(110,342)
Capital	0	(27,963)	(27,030)	(28,358)	0	0	(32,030)
Present Value (PV)	(91,027)	(46,078)	(45,300)	(48,529)	0	0	(46,655)
Net Present Value (NPV)	N/A	44,949	45,727	42,498	0	0	44,372
IRR%	N/A	16.0%	16.4%	17.5%	N/A	N/A	15.7%
Discounted Payback (Yrs)	N/A	10.15	9.94	10.85	N/A	N/A	10.32

Status Quo - Not Recommended

This is not an acceptable option and there are many unfavorable impacts. Operator simulator continuing training contact hours for simulator "hands-on" will drop further away from the ACAD minimum industry standard of 60 hours per year per operator. The industry median is estimated to be approximately 95 hours. DNGS is currently at 30-35 hours which is half of the minimum. The lack of an additional simulator will result in less than 30 hours and make this situation worse.
There is a risk to continued full operation of the plant if the required number of authorized staff is not maintained. A cascading negative affect on plant operation will occur when the training program no longer has authorized staff to support training and evaluation of currently certified staff and new initial trainees. Once this level is reached, the business will not be able to recover without significant business impacts. (See Attachment D).

There is a risk of Outage delays because there will not be enough certified staff to be assigned to the outage program, a possibility of an increase in preventive and corrective maintenance backlogs due to the inability of Operations to staff the work control area, staffing to support IPG and FIN will not be maintained, the procedural backlog will increase and the quality will decrease, and the issuance will have to be by duty ANO's. More importantly, there is a potential impact to the safe operation of DNGS nuclear reactor due to reduction of experienced operators.

The Regulatory body may order DNGD to comply to what was committed, should training and operational programs be found less than acceptable when evaluated against industry standards. There is a potential failure to meet OPG production targets, and to meet OPG business objectives to advance DNGS Operations and training programs to top industry standards.

With not building the second simulator at DNGS, continued travel costs of $125k/year and overtime costs of $1.1M/year (For 1 extra ANO coverage: $125k/h x 24 h/d x 365 d/year) would be incurred to increase shift complement which is currently only at 30 ANOs, to 45 ANO's (40 minimum complement and 5 ATS) starting in 2009 (See Graph A). This cost does not include ANOs in support of work control, outage, FIN etc.

Considering all the risks to OPG stated above, status quo option is not recommended.

Alternative 1 - Second Darlington Full Scope Simulator - Recommended

Provision of a Second Full Scope Simulator at the DLC will meet the four key business objectives for this project. It will address the staffing plan targets and ensure that sufficient certified staff are available (and maintained) to safely operate all Darlington units, meet OPG production targets, as well as provide necessary certified staff in support of other operational programs (e.g., training, outages, integrated operational planning, work control area, fix-it-now (FIN) teams, ...etc). It will also provide the means to develop and deliver "hands-on" training to meet industry standards and thus further OPG's objective to be a leader in the industry. The DLC structure currently has space provisions to house the new Simulator. Internal capital modifications will be required to create the new simulator training facility. This includes upgrades/installation of HVAC, Fire Protection, electrical, LAN, telephone, PA, structural, training classrooms, conference/maintenance rooms, etc.

Alternative 2 - Delay Project - Not Recommended

The decision to install a second simulator could be delayed until early 2009 when a final decision will be made whether to support station refurbishment to extent DNGD's service life beyond the current assumed date of 2018.

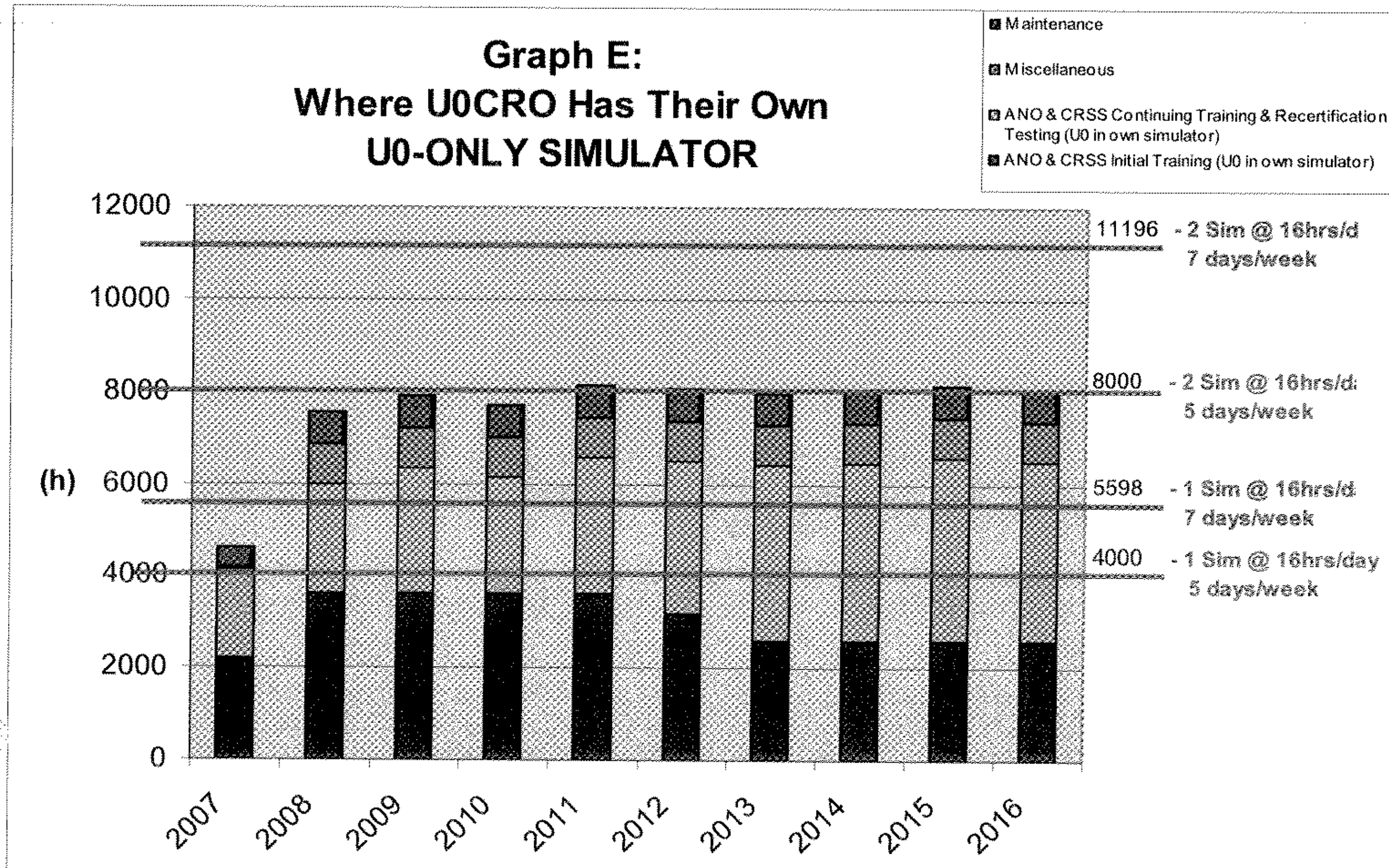
The advantage of delaying the project will be that the capital costs could be rolled into the cost of station refurbishment. However it should be noted that the costs of a second simulator will still need to be paid and the future costs may well be higher due to inflation. In addition the risk of delaying the decision for a second simulator will push back the time period for building the simulator. As time advances the obsolescence of hardware to support construction of the simulator will become more of an issue.

In short, delaying the decision to build a second simulator will result in the same adverse and unacceptable consequences as acceptance of the status quo. The delay of the decision will also further delay the eventual in service date for training purposes until Q1 2011 at the earliest. The primary drivers for an additional simulator are of concern today and will continue to drive the need for a second simulator into the foreseeable future. In addition there is a potential increased risk to procurement of the correct materials and components to construct the simulator due to aging and obsolescence.

Alternative 3 – Second Darlington Simulator – Unit 0 only - Not Recommended

The alternative of constructing the Unit 0 Simulator for Darlington was assessed as a reduced scope option. This may partially offset new U0 certification requirements, however the U0 simulator cannot be split in whole from the Unit training as the team has to practice and be tested together, similar to the station MCR environment. This option will also not address the larger area of need; reactor unit staff planning and training preparation/delivery issues. Improvements in the area of staffing rotational positions, increasing training development time and "hands-on" training time cannot occur with one simulator plus a new U0 simulator only.

Graph E below shows the remaining simulator usage hours still required for ANOs, CRSSs and SMs; where U0 CRO initial and continuing training has been extracted due to building a U0-ONLY simulator. While total overall usage did decline for the ANO/CRSS/SM when compared to Graph D, this new graph shows that the remaining simulator hours are equal to 2 simulators @ 16 hours/day for 5 days a week. To achieve this alternative a Full Scope U0-ONLY simulator (hardware and software) would still have to be built and commissioned. Even then, U0 would not be getting any overall control room practice in initial training and as discussed, the ANO/CRSS/SM needs would not be met.



Again, this option would not allow us to even start to address increasing regulatory and industry standards, expectations and requirements, or the requirement to increase "hands-on" time and other activities necessary to reach top industry standards. In fact, compensatory actions such as the recall of certified staff from current support programs would significantly and adversely impact areas essential to plant operation and is neither sufficient nor sustainable. On these bases, this alternative is not recommended.

Alternative 4 – Increase training hour to 24/7 - Not Recommended

By increasing training to 24/7, it slightly improves the simulator demand situation; however this option would require negotiation with both labour unions. A one time agreement with Society was already exhausted and would be very difficult to obtain again. Based on LOU – 119 for CRSS CRSOS, ATS, UOTS and SSIT, forced overtime is limited to 3 non-consecutive weeks per employee if voluntary overtime is not an option. Training during these off hours has also already been identified as a contributing factor to current failures as it leads to a lack in management oversight during training and leads to insufficient use of ATS resources.

Even if an agreement with labour unions is obtained, this option is insufficient to makeup for the shortfall in simulator hours (See Graph D, starting in 2008). Training 24 hours 7 days a week, and taking into consideration a 2% breakdown rate, a total of 8585 simulator hands-on hours are available. Again, this option would not allow us to even start to address increasing regulatory and industry standards, expectations and requirements, or the requirement to increase "hands-on" time and other activities necessary to reach top industry standards.
On these bases, this alternative is not recommended, however, may be required in the interim until such time as an additional Full scope simulator becomes available.

Alternative 5 – Second Darlington Full Scope Simulator at PLC - Not Recommended

The alternative of constructing the second full scope simulator at the PLC was assessed; however it is not considered a viable option. It may create continuity from a maintainability perspective and will eliminate the need for additional maintenance staff. However, placing the second simulator at the PLC would require an extension to the PLC. This requirement will cause the in service date of the second simulator to be delayed by 1 year due to design/permit/build durations. Modifying the DLC to accommodate the simulator allows a capital savings and an in service date which is acceptable to the stakeholders.

There would also continue to be a burden of $125k/year in travel costs for trainees to travel to Pickering for training. Constructing the simulator at the DLC reduces this cost, eliminates possible driving safety issues, and allows more effective training due to proximity to the station. This alternative is therefore not recommended.

/ THE PROPOSAL

Engineering, Procurement, Installation, and Commissioning of a second simulator in the existing footprint of the DLC facility. The DLC structure currently has space provisions to house the new Simulator. Internal capital modifications will be required to create the new simulator training facility. This includes upgrades/installation of HVAC, Fire Protection, electrical, LAN, telephone, PA, structural, training classrooms, conference/maintenance rooms, etc.

A fixed price bid has been agreed to for the purchase of the new simulator and the preliminary engineering portion of the contract is in progress under the current release. Once additional funding is approved via this release, the remainder of the PO will be enacted to ensure delivery in Q2 2009.

Preliminary Engineering has been completed for the DLC modification portion of the project.

This full release will fund the following key deliverables:

- Full Scope Simulator Project # 16-28452
  - Conforming fixed priced contract with Engineer, Procure, Construct (EPC) vendor
  - Work plans, and project schedule
  - Quality and control manuals, quality, safety, and environmental plan
  - Design plan, and engineering documentation
  - Inspection and testing plan, Factory Acceptance Testing, Site Acceptance Testing, and documentation
  - Training plan
  - Delivery of main simulator components and spare parts
  - Commissioning, turnover including AFS
  - Simulator fidelity assurance enhancements post AFS including technical support, material, and minor refinements. The accountability of the Fidelity assurance work will be transferred from P&M to Simulator and e-learning Technology Department upon completion of AFS in July 2009. P&M will update Project Closeout and Lessons Learned reports if required upon completion of fidelity assurance work.

- DLC Modifications Project # 16-28543
  - Contract for detailed engineering
  - Contract for construction of modifications
  - Work plans, assessments, and project schedule
  - Design Plan and NEF ECC documentation including new drawings
  - Quality and control manuals, quality, safety, and environmental plan
  - Design plan, and engineering documentation
  - Inspection and Testing Plan
  - Detailed commissioning specification
  - Commissioning report and plan

- AFS and lessons learned for both Projects # 16-28452/28453
- Project close out and PIR for both Projects # 16-28452/28453

5/ QUALITATIVE FACTORS

Constructing the Second Full Scope Simulator for Darlington has additional benefits that will specifically have an impact on:

Training Quality

Having a second full scope simulator provides greater flexibility for training and testing schedules including remedial training and testing for failed test results (that will not have to take away from other mandated training and testing programs, as currently occurs). It provides opportunity for greater Line Management involvement and ownership of training as the new facility will be located on site, and provides on-site opportunities for support of Provincial Emergency Exercises. In the future, when the initial training requirements will slightly decrease, it provides opportunity for training programs that are currently not running, to be incorporated to increase our chances in reaching top industry standards.

Employee Engagement

Having the opportunity to train additional licensed staff allows for employee movement throughout the organization and provides different career paths for employees. As well, it benefits the organization as it distributes operational and focused knowledge which supports other job positions at OPG. In addition, it will help with the quality of life for the instructors and trainees by reducing the weekend and early morning (12:00 to 4:00 am) training time and reduces the amount of traveling time during work hours.

Safety Events

Having the opportunity to increase the amount of hands-on time above the minimum will give the licensed staff confidence while working at the panel and this in turn will reduce the risk of operator error.
Driving from site to site contributes to an increased risk to personnel. By having a second simulator at Darlington, this risk will be eliminated and will reduce the exposure to OPG.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Exceeding release limit	Cost overrun	**Medium**	A fixed price bid has been received for the purchase of the new simulator. Preliminary Engineering is complete for the DLC Mods and an estimate of remaining engineering costs has been obtained from the Design Agent. A third party estimate has been obtained for the DLC capital modifications. This estimate was based on the previous simulator move project and the known differences have been accounted for in the BCS estimate. A specific contingency of $500K has been allocated for this phase of the project (16-28453) for execution coordination between several contractors to ensure compliance to schedule and expenditure does not exceed the release limit.	**Low**
Architectural/engineering agency utilized for the detailed design of the DLC for the move project unavailable to perform the work for this project.	This release assumes that much of the previous design, still owned by the AE firm can be re-used for this project. If not, both cost and schedule will increase.	**Medium**	Existing documentation is available and will be utilized to the greatest extent possible to reduce design costs. Schedule float associated with the DLC modification portion of the project will be used to accommodate their resourcing if required.	**Low**

Scope				
Scope for the DLC Mods may be increased by the Design Agency	Schedule and cost overrun	**Medium**	Design information developed during the Simulator Move Project will be utilized to ensure the scope is well defined taking into consideration identified preliminary design changes	**Low**
Schedule				
Schedule for completing the milestones may be delayed due to long lead material delivery	Schedule delay due to size and complexity of long lead materials and some obsolete parts.	**Medium**	Long lead materials have been identified in fixed price EPC for the Main Simulator. The schedule will be frozen upon award of contract	**Low**
Schedule may be delayed due to coordination among several contractors.	Cost overruns due to stand down time or delays. Delays to schedule.	**Medium**	Implement a phased execution for DLC Mods to lineup with the installation and commissioning of the simulator with OPG oversight and contract management	**Low**
Resources				
Lack of experienced Design support for this phase of the	Delay in completion of this phase	**Medium**	The design work will be completed by Design Agencies. Regular interface	**Low**

project			meetings will be held with the Design Agencies to ensure threats to schedule are mitigated and design requirements for both projects are met.	
Lack of experienced Project Engineering/Management support	Delay in completion of this phase	**Medium**	Project Leader II has been hired and group is staffing MP2/3/4 positions. Expected to be complete by end of June 2007.	**Low**
Technical				
Based on Previous simulator acquisition projects, the Second DNGS Simulator will have fidelity challenges which will impair its functions. 1. Station Changes made during the simulator project phases will be missing. 2. Fidelity of some Instruments will be inconsistent with the station.	1. Simulator training and Testing of Operations Staff at the DLC will not be possible on station changes because of the project design data freeze date (i.e controller replacements, device replacements, and Station Computer changes). 2. Differences in fidelity of some instruments between the simulator and the reference unit at the station may result in Auditor findings (i.e WANO AFIs). Experience from the Second Bruce A Simulator project was that some panel instrumentation as finally installed differed from the station equivalent which impaired panel fidelity.	**Medium**	Lessons Learned from experience on past simulator acquisition projects will be incorporated into the Second DNGS Simulator project's plan as follows. An allowance of $1M has been added to the project base cost to mitigate these technical risks. Project execution will be in phases to expedite the Ready for Training schedule: 1) a) Initial training and testing of Operations Staff on station changes can be performed on the DNGS Simulator at the PLC. b) Project resources are assigned to Simulator & eLearning Technology Dept to implement expected new changes to "catch-up" to the station. 2) Simulator Vendor purchase orders will be staged to allow for: a) Design and Development b) Manufacture through Initial Installation at the DLC c) All instruments will be functional to enable	**Low**

			Simulator Training after comissioning. d) Required instruments will be re-engineered and supplied to ensure fidelity with the station	
Regulatory				
CNSC may request an evaluation of our training program and enact a tighter timeline for in service to meet Industry Standards	Increased costs to meet requirements	**Medium**	Start project to demonstrate that OPG is moving to correct the deficiency of training and bring the training program up to industry standards.	**Low**
Environmental				
No significant risk for this release.				
Health & Safety				
There are health and safety risks to regular OPG employees and contractors during the construction phase. (Air quality, noise, electrical, craning, working at heights, etc..)	Potential harm to OPG emplyoees and contractors.	**Medium**	Implement control under OPG Health and Safety Plans. Pre and Post Job Briefs will be performed to inform workers of all hazards. Limited and controlled access to DLC working area will be inforced and only qualified personnel will have access	**Low**
Investment				

A decision may be made not to extend DNGS service life to 2044.	Decrease in IRR and NPV for project	**Low**	Risk Magnitude is too large to be managed at the Project level. Pending Coorporate Decision.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Comprehensive	**Jul 2009**	**Jun 2011**	**Manager Operations**

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Simulator Training hours	30-35 hrs/year/per	>60 hrs/year/per	Training stats	Training
2.	Meet minimum complement on each shift crew	6 ANO's per crew	8 ANO's per crew, and 15 ANO's for supporting roles	Operations shift schedules	Operations
3.	Reduction in OM&A travel time to PLC and Overtime costs to maintain shift complement	$125k/yr + $1.1M/yr	$0/yr	Cost reports	Operations
4.	Simulator Availability for Training	N/A – new simulator	Exceeds 98% [standard for all simulators]	Statistics on forced outages during Simulator Training for 6 months after AFS Completion 16-28452	Simulator & eLearning Technology Dept
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

ANO – Authorized Nuclear Operator
ATS – Authorized Training Supervisor
CRSS – Control Room Shift Supervisor
CRSSIT – Control Room Shift Supervisor In Training
EPC – Engineer, Procure, Construct
FIN – Fix It Now
INPO – Institute of Nuclear Power Operations
IPG – Integrated Planning Group
MCR – Main Control Room (Station)
NANT – National Academy for Nuclear Training
NPT – Nuclear Programs and Training

Appendix "B" — Project Funding History

Choose Project 28452 Release Type	Month	Year	All Existing and Planned Releases (incl contingency) Cumulative Values 2006	2007	2008	2009	2010	2011	2012	Later	Total
Developmental	Sep	2,006	69	864							933
Full	Aug	2,007		641	11,676	2,347	628				15,292
											0
											0
											0
											0
											0
											0
LTD Spent	Jun	2,007		339							339

$ 000's Project 28453 Release Type	Month	Year	All Existing and Planned Releases (incl contingency) Cumulative Values 2006	2007	2008	2009	2010	2011	2012	Later	Total
Developmental	Sep	2,006	0	0	0						0
Full	Aug	2,007		838	7,136	3,757					11,731
											0
											0
											0
											0
											0
											0
LTD Spent	Jun	2,007		220							220

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

- Based on agreed upon fixed price contract for EPC (Main Simulator).
- Based on Altus Helyar estimate for Simulator Move Project with considerations to known preliminary engineering changes (DLC Mods).
- Interest of 5.9% with allocated yearly cashflows up to 2009.
- Identified specific contingencies to manage risks
- 15% general contingency for accuracy of estimates
- Allowance for overtime and travel costs for Factory Acceptance Tests (FATs) and Site Acceptance Tests (SATs) to meet schedule and the phased approach implementation.
- AFS for Project 16-28453 in Q2 2009.
- AFS for Project 16-28452 in Q3 2009 and 100 % declaration report of equipment in service in Q3 2009
- Transfer of $100K for materials, 150K for FTE coverage, and $750K for Contract work to NPT in Q3 2009 to complete post AFS fidelity assurance work in 2009 and up to Q2 2010 based on OPEX. This work will be part of Project closeout activities without interest.
- Project closeout (ECC) in Q4 2009.
- Final Project closeout in Q4 2010.

Financial Assumptions:

- Escalation – 1.5%
- Discount Factor – 0.07
- Outage Overheads (k$/PO day) - $300

Project / Station End of Life Assumptions:

Currently end of life for DNGS is 2020, however a decision will be made in 2009 whether to support station refurbishment to extend DNGS service life to 2044. Based on CNO expectations, OPG is to plan DNGS investments assuming a life extension (End of Project Life 2044).

Energy Price / Production Assumptions:

- Unit MW Output - 878 MW
- Unit Energy Cost - $49.50 per MW

Operating Cost Assumptions:

N/A

Other Assumptions:

Additional ongoing Nuclear Programs and Training OM&A resources are required to operate and maintain a second simulator site and associated facilities. The incremental ongoing costs are based on 2010 and 1.5 % escalation onwards

The incremental OM&A resource increase for Simulator & e-Learning Technology Department required to maintain the Second Darlington Simulator includes two FTEs in 2008 and three FTEs afterwards[two extra M&P engineers and one extra PWU control technician] plus $100k per annum for material/spares/consumables. These ongoing costs are included in the 2008-2012 issue paper # 44 pending business plan and are estimated to be:

2008: $269,000
2009: $518,000
2010: $537,000
2011: $550,000
2012: $560,000
on-going

The incremental OM&A resource increase for Authorized Training to increase the amount of ATS Simulator Instructors to support the staffing for the current Business Plan includes five FTEs. These ongoing costs are included in the 2008-2012 issue paper # 44 pending business plan and are estimated to be:

2009: $1,125,000
2010: $1,177,000
2011: $1,194,000
2012: $1,212,000
on-going

The incremental OM&A resource increase for Nuclear East Facilities to maintain the DLC facilities includes 2 FTEs (one janitor and one control tech), and $300k for spare parts and supplies to support the additional facility. These ongoing costs are included in the 2008-2012 issue paper # 44 pending business plan and are estimated to be:

2009: $600,000
2010: $627,000
2011: $636,000
2012: $646,000
on-going

All the incremental OM&A costs presented are included in the 2008-2012 issue paper # 44-pending business plan and have been used to calculate the Net Present Value of the project.

Darlington Second Simulator 16 - 28452 Capital

Full Release Business Case Summary D-BCS-59000-10002-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2006	2007	This Release 2008	This Release 2009	This Release 2010	2011	2012	Later	Total
Project Management (OPG)	6	237	336	275	16				870
Engineering & Drafting (OPG)	41	165	744	302	130				1,382
Material				50	50				100
Installation – PWU, BTU		23	224	130					377
Contract - Design		970	705						1,675
Contract - Installation			7,753	442					8,195
Contract - Other				400	350				750
									-
									-
Interest (Capital Project Only)		21	391	442	-				854
Project Costs (excl contingency)	47	1,415	10,153	2,041	546	-	-	-	14,202
General Contingency		90	1,523	306	82	-			2,001
Specific Contingency									-
Project Costs (incl contingency)	47	1,505	11,676	2,347	628	-	-	-	16,204
2007-2011 Business Plan	250	1,350	11,050	2,253	-				14,903
Variance to Business Plan	(203)	65	(897)	(212)	546	-	-	-	(701)
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	47	1,415	10,153	2,041	546	-	-	-	14,202
Total Release (incl contingency)	47	1,505	11,676	2,347	628	-	-	-	16,204
Ongoing OM&A (non-project)			269	1,643	1,714	1,744	1,772	73,485	80,627
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	Up to ~ 15%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Sep 2007.

Reviewed By:

Vince Tzambazis
Project Manager

July 17, 2007
Date:

Approved By:

Dianne Gaine
Eng & Mods Manager (Strat IV)

July 17/07
Date:

DLC Modifications 16 28453 Capital

Full Release Business Case Summary D-BCS-59000-10002-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2006	2007	This Release 2008	This Release 2009	2010	2011	2012	Later	Total
Project Management (OPG)	22	191	286	103					**601**
Engineering & Drafting (OPG)		64	114	71					**249**
Material			50	450					**500**
Installation – PWU, BTU		23	380	144					**546**
Contract - Design		418	790	91					**1,299**
Contract - Installation			4,016	2,185					**6,201**
Contract - Other		23							**23**
									-
									-
Interest (Capital Project Only)	0	10	134	223					**368**
Project Costs (excl contingency)	**22**	**729**	**5,770**	**3,267**	-	-	-	-	**9,787**
General Contingency		109	866	490	-	-			**1,465**
Specific Contingency		-	500						**500**
Project Costs (incl contingency)	**22**	**838**	**7,136**	**3,757**	-	-	-	-	**11,752**
2007-2011 Business Plan	250	849	5,006						**6,105**
Variance to Business Plan	**(228)**	**(120)**	**764**	**3,267**	-	-	-	-	**3,682**
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	**22**	**729**	**5,770**	**3,267**	-	-	-	-	**9,787**
Total Release (incl contingency)	**22**	**838**	**7,136**	**3,757**	-	-	-	-	**11,752**
Ongoing OM&A (non-project)				**600**	**627**	**636**	**646**	**26,866**	**29,375**
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	Up to - 40%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	Yes	OPEX used	N/A	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	No	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Sep 2007.

Reviewed By: Approved By:

Vince Tzambazis July 17, 2007 Dianne Gaine July 17/07

Vince Tzambazis
Project Manager

Dianne Gaine
Eng & Mods Manager (Strat IV)

Second Darlington Full Scope Simulator Project 16 - 28452 Capital 16 - 28453 Capital

Full Release Business Case Summary D-BCS-59000-10002-R000

Attachment "B"

Project Variance Analysis

	LTD	Choose One		Variance	Comments
	Jun 2007	Last BCS Sep 2006	This BCS Jul 2007		
Project Management (OPG)	210	1,000	1,471	471	
Engineering & Drafting (OPG)	100	731	1,631	900	
Material	0		600	600	
Installation – PWU, BTU	0		923	923	
Contract - Design	243	2,930	2,974	44	
Contract - Installation		14,950	14,396	-554	
Contract - Other			23	23	
				0	
				0	
Interest (Capital Project Only)	5	1,173	1,222	49	
Project Costs (excl contingency)	**558**	**20,784**	**23,240**	**2,456**	
General Contingency		**3,109**	**3,466**	357	
Specific Contingency			500	500	
Project Costs (incl contingency)	**558**	**23,893**	**27,206**	**3,313**	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**558**	**23,893**	**27,206**	**3,313**	
Total Release (excl contingency)	**558**	**20,784**	**23,240**	**2,456**	

Ongoing OM&A (non-project)			**109,514**	**109,514**	
Removal Costs (incl in above)				**0**	

Comments:

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
15	June	2007	Purchase Order Issued - Preliminary Design 16-28452
04	Sept	2007	Full Release BCS Approved 16-28452/28453
02	Oct	2007	Design Agency Contract for Detailed Engineering Awarded 16-28453
11	Oct	2007	Purchase Order Issued - EPC 16-28452
21	Jan	2008	Contractor - Start Pre-fabrication of Panels 16-28452
09	April	2008	Contractor - Final Design Complete 16-28452
23	May	2008	Contractor - Final Design Complete 16-28453
23	May	2008	Award Installation Contract 16-28453
09	June	2008	Start Installation 16-28453
29	Sept	2008	Contractor - Start Installation of Panels 16-28452
08	May	2009	AFS Complete 16-28453
15	July	2009	AFS Complete 16-28452 (Ready for Training)
31	Dec	2010	Project Closeout Complete 16-28452/28453

A Project Execution Plan (PEP) will be approved by Aug 2007

Comments:

Fuel Handling Power Track Modifications - Capital - 16 - 31438

Full Release (Phase 1) Business Case Summary - NK38-BCS-63578 - 10010-R000

1/ RECOMMENDATION:

Approval is requested to release 8,530K$ to complete detailed design, procurement, installation, commissioning and some close out activities for the Full Release Phase 1 Fuel Handling Power Track Capital Improvement Project at Darlington. 5,800K$ has already been released previously under a Partial Release, bringing the total requested now to 14,330K$. Total project cost with Phase 2 is estimated to be 17,378K$.

The business objective of this project is to significantly reduce the risk that an undetected Power Track (PT) component failure will lead to extensive damage of the fuel handling system, causing lengthy forced outages and a large financial setback, such as that which occurred at Darlington in 2004 ($45M associated cost).

An extensive front end planning process was used to ensure that the risks were identified, risk mitigation actions were put into place and a detailed estimate, including input from a third party estimator. The result of this process has been to take a two phased funding release approach for the Capital project, the goal of which is to ensure that highly reliable systems are introduced to the station.

The objectives of this project are:

- To install a Dynamic Instrumentation measurement system on the Power Track trolley, chain and yoke assembly to collect data to better understand the dynamic forces leading to component failures. This will allow the Design Agency to develop a better long term solution to avoid any future component failures.
- To install a Video Surveillance System to add real-time surveillance in the event of a component failure. This will replace the currently existing temporary camera installations (TMOD) that have begun to fail.
- Risk mitigation work and a pilot project for a Dropped Roller Detection system. The goal of the system is to ensure early detection of any drum roller failures, thus avoiding extensive damage and lengthy forced outages.

An associated OM&A project (16-38472), for a Variable Frequency Drive (VFD), will be justified in a separate Full Release BCS.

Complete preliminary and most detailed engineering has already been completed on all three Master ECs. There are still some technical questions about the performance and reliability of the Dropped Roller Detection system; as a result a Phase 1 and Phase 2 release funding strategy is being utilized. This release includes a funding request to complete installation of two ECs (Dynamic Installation and Video Surveillance System), including completion of material procurement, installation and project close out costs and some risk mitigation work including a pilot trial for the Dropped Roller Detection system.

$000's (incl contingency)	Funding	LTD 2007	2008	2009	2010	2011		Later	Total
Currently Released	Partial	652	2,694	2,438	16				5,800
Requested Now	Full - Phase 1			2,487	3,730	2,313			8,530
Future Funding Req'd	Full - Phase 2							3,048	3,048
Total Project Costs		652	2,694	4,925	3,746	2,313	-	3,048	17,378
Other Costs									-
Ongoing Costs									-
Grand Total		652	2,694	4,925	3,746	2,313	-	3,048	17,378
Investment Type Sustaining		Class Capital		(IEV) Impact on EC Value +69.5 M$		IRR 897.0%		Discounted Payback 1.1	

Submitted By:

S Seidl for 23 Dec 2008

Name: W. Robbins Date:
Title: Senior V.P. Darlington

Finance Approval:

Name: D. Power Date: Jan 26/09
Title: V.P. Corporate Investment Planning

Line Approval (Per OAR Element 1.1 Project in Budget):

Name: P. Charlebois Date: Jan 27/09
Title: EVP & Chief Operating Officer

2/ BACKGROUND & ISSUES

The Fuel Handling Power Track (FHPT) system is used to refuel all four reactors at Darlington A. In this system, there are three separate track/trolley pairs that run for approximately 500 metres along the south face of the reactors in the Fuel Handling Duct. The trolleys run along the track using a series of drum rollers and are driven by two motors; a Course drive motor for high speed movement and a fine drive motor for positioning to refuel. Their operation is vital to keeping the reactors at optimum levels and maximizing the plants electricity generation.

The FHPT has experienced a number of component failures attributed to mechanical stress and wear. In January of 2004, an intermediate roller failed during the coarse W drive (high speed) motion of the trolley. This roller caused significant damage to the Power Track before the trolley came to a stop and resulted in a 21 day outage of unit 2 and de-rating of unit 1 to 59% for 15 days. The cost of this event was 45M$ to the station.

The incident investigation under SCR D-2004-00642 identified that the dropped roller had likely failed on one side around the time of the station containment outage in October 2003. The affected roller was one which was only inspected annually and had been missed in the last inspection. The incident raised the concern that such an event could result in the loss of trolley coolant inventory and mobility at the same time (SCR D-2004-02632).

After the event, an extensive and exhaustive risk assessment (Darlington NGS-Fuelling Machine Power Track Risk assessment P0440/RP/005, Nov. 5, 2004) was undertaken by an external Design Agency. One of the five main conclusions of the study was that "the financial risk of power track failures is estimated at 17M$ per year, equivalent to about 20% of the financial risk associated with reactor accidents for the entire station". The risk of a repeat Power Track failure has been significantly reduced by the ongoing Power Track Improvements (replacement of intermediate roller endplates). However, the long term performance of these new components is unknown due to their limited operating experience and a lack of understanding of the Power Track dynamics.

The FHPT system has limited surveillance capability to detect deteriorating or failed components. The isolated location and limited access to the Fueling Duct make it difficult to detect failed components. The limited number of existing cameras that monitor critical fueling activities cannot be adequately used for this purpose. The barriers to effective system surveillance due to access restrictions and limitations of the existing cameras make it difficult to implement an effective maintenance program. Modifications are needed to enhance surveillance, failure detection and diagnostics, which should ensure that failed components are detected and repaired before they develop into significant events.

Ongoing Power Track Maintenance activities requiring numerous No-Fuel Windows (NFW) have sustained the system's status. These activities are temporary in nature and a permanent solution is still required. Reliability Improvements are needed to maintain the system status at white and ensure availability requirements are achieved. These improvements, as previously discussed, are:

- Increase system monitoring capabilities.
- Understand dynamic loads on the Power Track coupling frame, chain and yoke.

Two permanent modifications and one risk mitigation pilot project are proposed under this BCS:

- Power Track Instrumentation System – for Power Track dynamics data collection and future analysis
- Video Surveillance System upgrades – for failed roller and system surveillance
- Dropped Roller Detection system – for failed roller detection capability pilot project

Dynamic Instrumentation System

The purpose of the Dynamic Instrumentation System is to provide data which can be used to assess the cause of the observed component failures, and provided a means to baseline the dynamic conditions to which the Power Track is exposed. The goal of the data acquisition system installed in this project is to ensure that any redesign takes into account the actual dynamic conditions and will also be useful for indirect measurement of future drum roller failures, if they do occur, and failed welded track.

The dynamic instrumentation installation will include a combination of tri-axial accelerometers, strain gauges on the chain links and force measurement on the tow yokes. The proposed system is similar to that recommended by a third party consultant as a "minimal instrumentation system". An external vendor has indicated that a phase II may be required if the data uncovers the need for more specific force data. The current understanding of the PT dynamics is insufficient to confidently redesign components to correct design deficiencies.

Video Surveillance System Upgrades:
The purpose of the camera system upgrade is to enhance the ability to perform both routine and non-routine surveillance and detect failures of critical components of the PT. Additional cameras, replacement of obsolete equipment and correction of lighting issues would allow regular inspection of critical components. Partial installation of this system is targeted for VBO in 2009.

Dropped Roller Detection System
The purpose of the dropped roller detection system is to alert the operator to a failed roller endplate so that the condition can be corrected before further equipment damage results. The dropped roller detection system will employ a laser to detect failed endplates when the first side of the drum axle drops and alert the operator to investigate using the cameras.

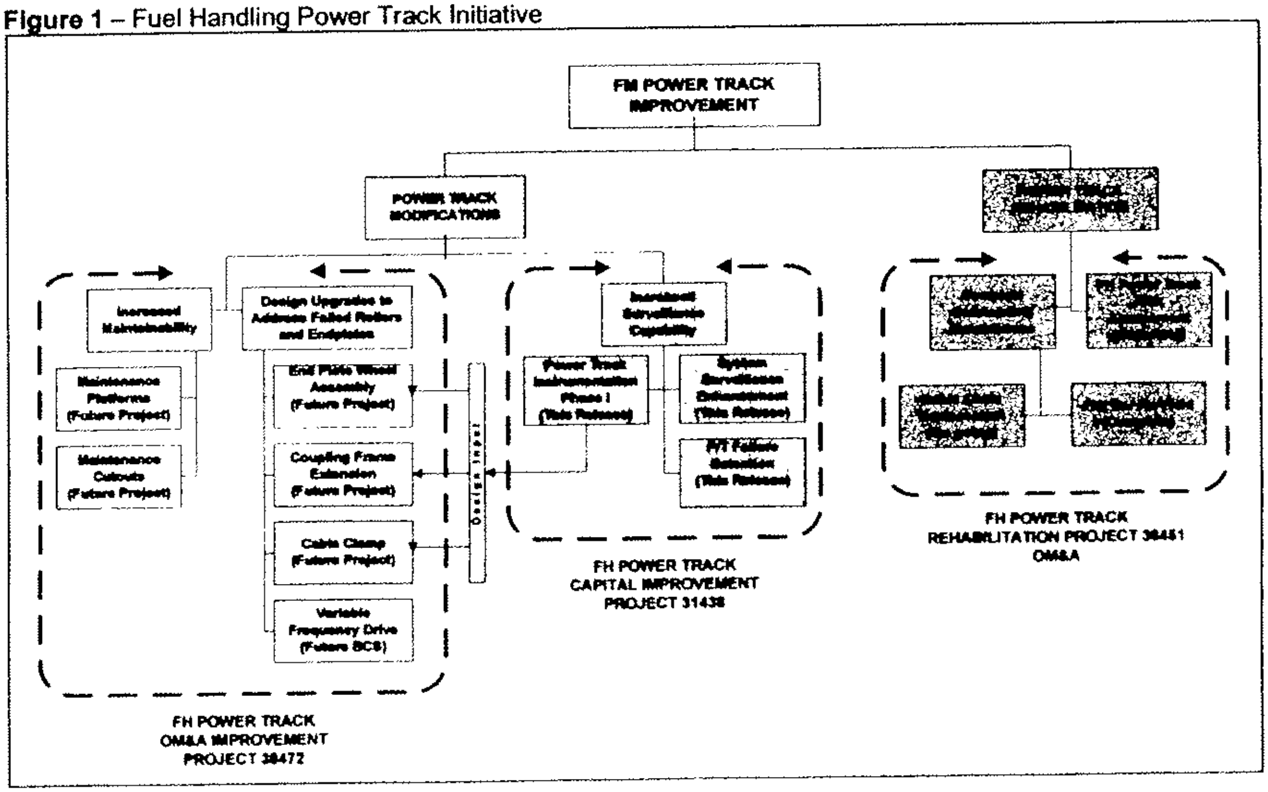
Experience indicates that the initial failure of the roller would permit movement of the track for inspection and repair. After some risk mitigation work and a pilot site is performed in this phase, the system will be fully implemented in a Full Release Phase 2 through the online scheduling process.

General:

The overall Fuel Handling Power Track Improvement Initiative is illustrated in Figure 1 below. Most of the Rehabilitation projects under the initiative have been completed, with the cable replacement being an ongoing maintenance item. Under the Power Track Modifications, some temporary measures have been put in place, including an improved manufacturing process for the endplate assemblies. However, the next phase of the Initiative is going to be implemented under this Capital Project, 16-31438. A final series of modifications will be implemented under OM&A, including the Variable Frequency Drive under 16-38472 and a number of future projects.

For the Capital Project (16-31438), an external vendor is currently working on the final aspects of detailed design for two of the three ECs (Dropped Roller Detection and Dynamic Instrumentation). The Video Surveillance System designs for release 3 and 4 have not yet been started, and an RFP will be issued when additional funding is available. Budgetary quotes have been received on most remaining design work and some of the installation work; these were used in the project estimates. There will be only a limited amount of work for the Video Surveillance System injected into the VBO, with most of the work performed through the IPG process (VSS Releases 1, 3 and 4, Dynamic Instrumentation and Dropped Roller Detection).

Figure 1 – Fuel Handling Power Track Initiative



3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3	Alt 4	Alt 5
Revenue							
OM&A							
Capital		(16,873)	(14,423)	(16,973)			
NPV (after tax)	(79,493)	(12,005)	(10,043)	(10,884)			
Impact on Economic Value (IEV)	N/A	67,488	69,450	68,609			
IRR%	N/A						
Discounted Payback (Yrs)	N/A						

Note: PV shown for the status quo is derived from NSS report PO440/RP/005 Nov. 5, 2004, which indicates that the financial risk associated with the power track failures that affects trolley motion is estimated at $17M per year. To reduce major failure risk, Power Track maintenance in the form of flat-bar re-weld and endplate roller replacement have been completed and chain replacement is an ongoing maintenance issue. Although these maintenance costs are significant, the overriding concern is the expense and safety implications associated with a repeat 2004 event. None of the proposed activities can entirely eliminate the risk.

Status Quo - Not Recommended
The status quo situation may allow the root cause of the previous failure of the Power track to remain. Maintenance effort alone may not be sufficient to address the deterioration of the Power Track. Failure to address the potential for further equipment failure poses a moderate to high risk for a repeat of the 2004, which resulted in a significant loss of production. There have been some significant improvements to the Power Track including weld repairs, endplate roller replacements and increased maintenance which may improve the overall reliability. However, the underlying causes of the PT failure still continue to exist and need to be better understood for long term reliability.

Alternative 1 - Complete Installation of Video Surveillance and Dynamic Instrumentation and risk mitigation work for Dropped Roller Detection - Recommended
Installing the Video Surveillance system and the Dynamic Instrumentation in Full Release Phase 1, in addition to performing some risk mitigation, condition assessment work and a pilot run for the Dropped Roller Detection. This option would ensure that the ability to detect a failure through surveillance is improved and data is collected for potential Power Track component redesigns. This would not have the automatic detection capability of the Dropped Roller Detection System, but would prepare for it's release in Full Release Phase 2.

Alternative 2 - Delay Project 2 years - Not Recommended
A delay of the project will directly delay implementation. Work delayed outside of the VBO will require multiple outage cycles to fully implement, and will have to complete for scarce no-fuel windows. If events lead to a renewed desire to pursue these modifications, no design alternative will be available. There is no benefit in delaying the installation phase of these projects.

Alternative 3 – Complete Installation of Capital Improvements - Not Recommended
Complete installation activities for the all ECs currently underway in the Power Track Capital improvement project. The current EC packages are the Dynamic instrumentation, the Dropped Roller Detection System and the Video Surveillance System upgrades. This option is not recommended due to the fact the Dropped Roller Detection System has not been proven in use and the reliability and performance can not be quantified at this point in time.

Alternative 4 – Dynamic Instrumentation First - Not Recommended
Installing Dynamic Instrumentation in the Power Track first. The rationale behind this approach would be to gain a better understanding of the cause of the component failures before implementing design solutions. This would be done by analyzing the force and vibration data from the coupling frame with accelerometers, strain gauges on the drive chains and load cells on the drive pin yoke. The lead time to execute two separate design and installation cycles, combined with the outage installation constraints will not address reliability and safety concerns in a timely manner.

Alternative 5 – Video Surveillance System Only - Not Recommended
Implementation of the augmented video surveillance system only. This approach would address the deficiencies and limitations of the existing system and would allow for enhanced regular inspections. However, it would not address reliability and may not detect a dropped roller in time to prevent damage.

Alternative 6 – Dropped Roller Detection Only - Not Recommended

Implementation of the Dropped Roller Detection system only. This approach is inconsistent with safety principles, in that it does not anticipate, prevent, or reduce the likelihood of an event. But would detect a dropped roller and potentially allow inspection and corrective action to occur before the event progressed to cause significant damage. This approach would not reduce the frequency of events, and Power Track reliability would continue to pose a production risk. Failures or inadequacies of other components would in no way be addressed and reliability would be expected to decline.

4/ THE PROPOSAL

Complete the detailed design of the remaining releases of the Video Surveillance System and installation of the video surveillance system upgrades, Dynamic Instrumentation ex-containment and perform risk mitigation/condition assessment work for the Dropped Roller Detection system. If the Dropped Roller Detection risk mitigation work is successful, then a Full Release Phase 2 will be required to complete the installation of this system.

The Full Release Phase 1 funding covers the following deliverables:
1) Project Execution Plan
2) Installation of Release 2 of the Video Surveillance System (VSS) during VBO.
3) Detailed Design, Procurement and installation of Release 3 and 4 of the VSS.
4) Completion of commissioning of the VSS.
5) Procurement and installation of the Dynamic Instrumentation (DI) System.
6) Commissioning of the DI System.
7) Risk mitigation work, pilot project and some Procurement for the Dropped Roller Detection (DRD) System
8) Training for Operations, Maintenance and the Performance Engineering Staff on the new systems
9) New and/or revised Operating and Maintenance Procedures
10) ECC related closeout activities for the DI and VSS, as well as lessons learned for the DRD

The Full Release Phase 2 funding will cover the following deliverables:
1) Updated Project execution plan
2) Incorporate lessons learned from the DRD Pilot Project, if necessary
3) Final Procurement and Installation of the DRD system, including control panel functionality
4) Commissioning of the DRD system
5) DRD Design closeout and Final Project Closeout
6) Post Implementation Review and Lessons Learned

Implementation of the proposed modifications will improve the Power Track reliability by facilitating identification of failed components (VSS and DRD) and providing valuable data that will be used in the redesign of components to better suit the Power Track dynamics (DI).

5/ QUALITATIVE FACTORS

Reduce the risk of another major Power Track failure through reduced operator reliance and improved overall Power Track reliability.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Installation Costs will exceed estimates – all projects	Installation contracts are done on a T&M basis, which means that changes in scheduled maintenance windows could drive up installation costs	<u>High</u>	Using Fuel handling maintenance and operations personnel where possible	<u>Medium</u>
Higher than expected engineering support costs	The resulting project spending for the installation and closeout would be higher	<u>High</u>	Have worked to better define the scope and expectations, updated the estimates accordingly	<u>Medium</u>
Redesign required because of technical/functional issues	The project will spend additional money on engineering changes and installation	<u>Medium</u>	Where possible, walkdowns, condition assessments and mock ups will be performed.	<u>Low</u>
Low initial material estimates from Design Agency may lead to higher final costs	Low initial quotes could lead to low material estimates in the Project Budget	High	The project will add some additional cost to the estimates in line with previous field experience	Low
Lack of available/rescheduled no fuel windows for online work	The contractors will be paid for wait time, which could become very expensive due to the number of installers involved	High	Contingency will be added to the estimate	High
Scope				
Discovery work during installation – Dropped Roller Detection system	The project might be force to add scope as a result of unknown field conditions	<u>High</u>	The project has performed a number of walk-downs to understand the field condition	<u>Medium</u>
Schedule				
Discovery work during installation	The installation could take additional time as a result of a newly discovered condition.	<u>High</u>	The project has performed a number of walkdowns to better understand the existing Power Track conditions	<u>Low</u>
Lose outage window during VBO – Video Surveillance System	The ability to complete the camera work will be reduced because of getting a reduced or lost VBO outage window.	<u>Medium</u>	Maintain the VBO milestones for the required camera work	<u>Low</u>
Additional Scope identified for Ex-containment - Dynamic Instrumentation	A noise level higher than expected will required a different design	<u>Medium</u>	Complete test early to prevent a potential redesign	<u>Low</u>

Camera design work for R3 and R4 will be done by an external vendor	Delay of placement of P.O. or delivery of final design will have an impact on the final design	<u>**High**</u>	Currently negotiating with existing vendor to expedite the design proposal and commercial issues	<u>**Medium**</u>
Resources				
Lack of FE or CMO support for installation	Delay of installation work for the Video Surveillance System, the Camera work and the Dropped Roller Detection System	<u>**Medium**</u>	Sequence and load level the project work so that demand for resources are spread over a greater period of time.	<u>**Low**</u>
Technical				
The performance of the Dropped Roller Detection system.	Because of existing conditions in the F/H Duct, the system may not perform or be as reliable as required. The result may be a write off of the system if it can not be corrected	<u>**Medium**</u>	Perform risk mitigation and condition assessment work during Full Release Phase 1 to ensure that the system can meet the system performance and reliability requirements, which will then be pursued in a Full Release Phase 2 BCS.	<u>**Low**</u>
Regulatory				
n/a				
Environmental				
Contamination in the material being removed for the existing TMOD	Radiation exposure to personal outside the Fuel Handling duct.	<u>**Medium**</u>	Put in place specific work plans to deal with the removal of the existing TMOD including contacting the appropriate disposal group.	<u>**Low**</u>
Health & Safety				
Radiation Exposure during installation activities	Due to the location of the installation activities, there is a risk of larger doses to some installation crew. This is especially true during online work.	<u>**Medium**</u>	Early Involvement of Radiation Protection control in Workplan development to ensure limited doses	<u>**Low**</u>
Investment				
The benefits of this investment not realized	The systems implemented do not eliminate a major failure event in the Power Track	<u>**Medium**</u>	Depending on the outcome of the Phase 1 release for the Dropped Roller Detection, a phase II plan will be implemented that ensures high reliability for the system	<u>**Low**</u>

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Feb 2013	Nov 2013	Manager, Fuel Handling

Comments:
Thes PIR is applicable to the Video Surveillance System project.

Table 1

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Sustaining – Avoid derating through Improved Power Track Surveillance	Existing camera system is failing and does not cover existing coverage area	90% increase in the surveillance area resulting in improved performance due to increased fueling	% of visibility coverage of Power Track endplates during normal operation and reduced operator dose	SRE – Fuel Handling
2.	Sustaining – Avoid derating through improved Trolley Camera Availability	Current system is failing which requires a deviation request from the Operating Manual	Uninterrupted surveillance of fuelling operation using – increased trolley camera availability	Camera Availability	SRE – Fuel Handling
3.	Sustaining – Avoid derating through improved availability of the FFAAs	Current FFAA Bay camera does not cover required view of manual operation In ancillary ports	90% increase in surveillance coverage of manual operation in FFAA ancillary port	Total surveillance coverage of the ancillary port manual operation	SRE – Fuel Handling

Comments:
This PIR is only applicable for the Dynamic Instrumentation Project.

Table 2

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Sustaining – Monitoring to determine baseline data for potential design change	Currently have a lack of data for the Power Track Dynamics	Collect Power Track Dynamics load data for redesign or failure analysis as necessary	Capability to collect Power Track dynamic load data for redesign of power track components	SRE – Fuel Handling

Comments:
This PIR is only applicable to the Dropped Roller Detection System project.

Table 3

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Sustaining – Avoid derating through early detection of power track failures.	Existing Trolley system is susceptible to undetected failure	100% Power Track failure detection capabilities.	Success rate in detecting dropped rollers in commissioning testing	SRE – Fuel Handling

Appendix "A" Glossary (acronyms, codes, technical terms)

CSA – Central Services Area
ECC – Engineering Change Control
FHPT – Fuel Handling Power Track
FM – Fuelling Machine
PO – Purchase Order
PT – Power Track
T&M – Time and Material
VBO – Vacuum Building Outage
VFD – Variable Frequency Drive

Appendix "B" Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2007	2008	2009	2010	2011	2012	2013	Later	Total
Partial	Nov	2007	652	2,694	2,438	16					5,800
											0
											0
											0
											0
											0
											0
											0
LTD Spent	Sep	2008	683	2,278							2,961

Comments:

A partial release for both the Capital and OM&A. There is a total of $[redacted]of unallocated contingency that will be carried from the partial release into the Full Release Phase 1 to offset some of the contingency requested.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

Design Costs for the remaining portions of the Video Surveillance system were extrapolated from the design work done for Release 1 and 2. There is some risk of increase due to the fact the work will likely be time and material type of contracts. The installation costs were done by an outside agent for the Video Surveillance System, based on most of the work being done online, with a limited scope in the VBO.

The installation costs for the Dynamic Instrumentation were also done by an outside agent based on the assumption that all work would be performed online. In the case of the Dropped Roller Detection, all work was assumed to be done online, with potentially some condition assessment work done during VBO. All installation work is assumed to be Time and Material done primarily by outside contractors.

All major material quote information was incorporated into the project cost estimates, and estimates were given for the remaining material based on bulk prices.

For the online installation work a factor of two (2) has been applied to the installation estimates due to the no fuelling window availability uncertainty. This estimate was used based on previous experience, and an additional contingency of 30% was also applied for installation work only. The general contingency applied to the procurement, support and installation activities was [redacted]%. As a result the final contingency amount is [redacted]% for the overall project cost estimate.

Financial Assumptions:

Project / Station End of Life Assumptions:

2018

Energy Price / Production Assumptions:

Operating Cost Assumptions:

Operating costs will be minimal. Periodic replacement of cameras and other equipment will be required. Installation PC and associate software will become obsolete.

There will be no reduction in maintenance effort as this is for sustaining and reliability improvement. Thus the assumption includes no reduction in manpower.

Other Assumptions:

In-service dates and amounts for the three separate ECs are as follows:

1) Video Surveillance System – 2909K$ - Oct 2010
2) Dropped Roller Detection phase 1 – 1758k$ - May 2011
3) Dynamic Instrumentation – 3493K$ - Aug 2011

Fuel Handling Power Track Modifications – Capital - 16 - 31438

Full Release (Phase 1) Business Case Summary NK38-BCS-63578-10010-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2008	2008	2009	This Release 2009	2010	This Release 2010	This Release 2011	Later	Total
Project Management (OPG)	504	133	536	262	10	588	598	906	3,537
Engineering & Drafting (OPG)	709	27	350	137		116	116	84	1,539
Material	173	[redacted]							
Installation – PWU, BTU		[redacted]							
Contract - Design	1,500	[redacted]							
Contract - Installation		[redacted]							
Contract - Other									-
									-
									-
Interest (Capital Project Only)	75	25		180	-	135	90		505
Project Costs (excl contingency)	2,961	[redacted]							
General Contingency		[redacted]							
Specific Contingency									-
Project Costs (incl contingency)	2,961	385	2,438	2,487	18	3,730	2,193	3,048	17,258
2009-2013 Business Plan		3,379	3,125		387				6,891
Variance to Business Plan	2,961	(2,994)	(954)	2,110	(377)	3,129	1,902	2,438	8,215
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory							120		120
Total Release (excl contingency)	2,961	[redacted]							
Total Release (incl contingency)	2,961	385	2,438	2,487	18	3,730	2,313	3,048	17,378

Ongoing OM&A (non-project)									
Removal Costs (incl in above)									

Basis of Estimate					
Design Complete	Most DPs @ 100%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	No
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	N/A	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2009-2013 Business Plan will be addressed through the portfolio management process. A PCRAF is not required at this point.

Reviewed By: 24-NOV-08

Name: Pete Reitknecht
Project Manager

Date:

Approved By: Nov 24/08

Name: Peter Floyd
Eng & Mods Manager (Strat IV)

Date:

ONTARIOPOWER GENERATION

Fuel Handling Power Track Modifications 16 - 31438

Full Release (Phase 1) Business Case Summary NK38-BCS-63578-10010 – R000

Attachment "B" **Project Variance Analysis**

Capital	LTD Sep 2008	Choose One: Last BCS Nov 2007	Choose One: This BCS Nov 2008	Variance	Comments
Project Management (OPG)	504	830	3537	2707	Increased scope and duration of support
Engineering & Drafting (OPG)	709	917	1539	622	Additional scope during installation
Material	173	[redacted]			detailed estimates completed for full release
Installation – PWU, BTU		[redacted]			detailed estimates completed for full release
Contract - Design	1500	[redacted]			Design Agency costs have increased
Contract - Installation		[redacted]			Now IPG (not VBO) and large amount of commissioning required
Contract - Other				0	
				0	
				0	
Interest (Capital Project Only)	75	315	505	190	
Project Costs (excl contingency)	**2961**	[redacted]			
General Contingency		[redacted]			
Specific Contingency		[redacted]			
Project Costs (Incl contingency)	**2961**	**9285**	**17378**	**8093**	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**2961**	**9285**	**17378**	**8093**	
Total Release (excl contingency)	**2961**	[redacted]			

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

A detailed estimate was completed as part of the front end planning process, including third party estimates for the installation portions of the project. As a result, the final estimates are higher than originally estimated; partially due to the fact that all but release 2 of the Video Surveillance System will be installed using the Online process (not during VBO).

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
15	02	2009	Installation Start of Video Surveillance System Release 1
15	06	2009	Detailed Design complete for Video Surveillance System Release 3
15	09	2009	Detailed Design complete for Video Surveillance System Release 4
15	02	2010	Installation Start of Dynamic Instrumentation System
15	04	2010	Installation Start of Dropped Roller Detection Phase 1
30	09	2010	AFS Video Surveillance System
30	07	2011	AFS Dynamic Instrumentation System
25	08	2011	BCS Phase II release

A Project Execution Plan (PEP) will be approved by Feb 2009

Comments:
The PEP will be completed upon approval of the Phase 1 BCS

DNGS Maintenance Facility 16 - 31717

Partial Release Business Case Summary D-BCS-28200-10003-R000

1/ RECOMMENDATION:

Approval is requested for this Partial Release of $6,935K capital (including contingency) to facilitate the demolition of the Power House Annex (PHA), FE Calibration Shop, Bldg 6 Security Change Room, & ERT Offices at Darlington as well as to complete the design for the relocation of buried services and to start the Preliminary Engineering portion only for the new Maintenance Facility. At this stage, present estimated total project cost is $44.6M ($57.7M including contingency) $1,600K of which is required for building demolition. A Full Release BCS is scheduled for May 2009.

The objective of this project is to provide new permanent shops and office space for DNGS maintenance staff with a safe and effective work environment. Failure to implement this improvement would leave the station vulnerable to decreases in maintenance productivity and effectiveness, potential increase of industrial accidents, and potential outage extensions due to lack of facilities for rehearsal space for RM and IMS.

The (PHA), FE Calibration Shop, Bldg 6 Security Change Room, & ERT Offices are in the footprint of the proposed new site of the Maintenance Facility and must be removed as a pre-requisite. These buildings are vacant and life-expired and will require removal regardless of whether the new Maintenance Facility goes forward as a Project.

This Partial Release BCS strategy has been adopted to facilitate removal of the PHA in 2008 and to facilitate timely engagement of engineering activities to minimize cost and schedule risks of the overall Maintenance Facility Project by obtaining a clearly defined scope of work for the buried services relocation and building plant and service tie-ins prior to the issuance of the EPC contract

Specifically, this Partial Release will complete:

- Decommissioning and removal of the existing DNGS PHA, Security Change Room, FE Calibration Shop & ERT Offices.
- Detailed Engineering of the Buried Services relocation and Tie-Ins required at the proposed site of the new Maintenance Facility.
- Issue Request for Proposal (RFP) and evaluate bids for a contract to install Tie-Ins and Buried Services relocations.
- Issue an RFP and complete bid evaluations for a Commercial Engineer, Procure, and Construct (EPC) contract for the new Maintenance Facility.
- Preparation of PO for the Preliminary Design portion for the Maintenance Facility to start design work for the new maintenance facility.
- Prepare a Full Release BCS.

Acres Sargent & Lundy (ASL) was commissioned to perform a study and develop several alternatives based on the priority of needs specified by the sponsor. The option selected by management is a new 2 story 60,000+ sq. ft building which meets all the needs identified except a welding shop.

This project will be executed between 2007 and 2011:

2007 - Preliminary Design for the PHA removal. (complete)
2008 - Removal of the PHA and associated buildings.
- Complete Detailed Engineering for the Buried Services relocations and Tie-Ins at the proposed site.
- Issue an RFP for a Commercial EPC contract for the proposed new Maintenance Facility, receive & evaluate bids.

2008/09 - Preliminary and detailed design of the Maintenance Facility.
2010/11 - Construction and turnover of the Maintenance facility to OPG Operations and Maintenance.
2012 - Close-out

Note that this project estimate does not include costs for moving existing maintenance equipment, purchase of new maintenance equipment, purchase of radiation monitoring equipment.

Full project cost estimates are conceptual at this time (+60% / -25%) and include approximately [redacted] contingency. Before requesting full funding release, detailed estimates will be completed and independently validated by a third party vendor.

An Executive Control limit of $50 Million has been placed on the project as a whole; expenditure beyond this limit must receive formal approval by the Chief Nuclear Officer and the Chief Operating Officer prior to expenditure or cost commitment.

$000's (incl contingency)	Funding	LTD 2007	2008	2009	2010	2011	2012	Later	Total
Currently Released	Developmental	1,369	234						1,603
Requested Now	Partial	(861)	3,960	3,836					6,935
Future Funding Req'd	Full			15,096	19,985	13,599	521		49,201
Total Project Costs		508	4,194	18,932	19,985	13,599	521	-	57,739
Other Costs									-
Ongoing Costs									-
Grand Total		508	4,194	18,932	19,985	13,599	521	-	57,739

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Sustaining	Capital	51.4M$	13.4%	N/A

Submitted By:

Tom Mitchell — Date: May 08, 2008

CNO

Finance Approval:

Donn Hanbidge — Date:

SVP & CFO

Line Approval (Per OAR Element 1.1 Project in Budget):

Jim Hankinson — Date: May 26/08

President & CEO

I BACKGROUND & ISSUES

DNGS needs to improve its overall maintenance capability to support continuous station operations in a safe and cost effective manner. Darlington initially commissioned a study of a Maintenance Facility under a partial release in 2002, that release was later cancelled due to changing station priorities. Subsequent studies by Wardrop (2005), Acres Sargent & Lundy (ASL) (2006), and most recently ASL to provide a revision to their 2006 study were commissioned; several iterations to the study were required due to changing maintenance strategies, changing management directives, station priorities, and budgetary constraints on the scope of the work.

The Maintenance Facility Conceptual Study rev 00 performed by ASL, which was issued November 13th, 2006, had four developed layouts and conceptual cost estimates, which significantly exceeded the portfolio budget. A new scope of work was provided by the Sponsor on December 13th, 2006 with scope ranked by priority and a cost ceiling for the new Maintenance Facility. ASL was re-engaged and an additional three new conceptual layouts, schedules, and cost estimates produced as a result of the iterations required to be developed to determine the optimal building layout while adhering to the stipulated scope priority and budget limitation.

The (PHA), FE Calibration Shop, Bldg 6 Security Change Room, & ERT Offices are in the footprint of the proposed new site of the Maintenance Facility and must be removed as a pre-requisite to the new build. These buildings are vacant and life-expired and will require removal regardless of whether the new Maintenance Facility goes forward as a Project. The removal & decommissioning cost is estimated at $1.6M (+60/-30%) and was obtained from rev 00 of the ASL conceptual report. The current construction change room is also in the foot print of the proposed Maintenance Facility. The removal of this building is being completed under project 31718 "New Construction Change Room".

As a result of DNGS progressing through its life cycle, changes in technology, new maintenance strategies, and loss of expired temporary buildings, the current maintenance facilities at Darlington are no longer adequate. The issues that were evaluated to develop the recommended option include the following:

Increased Maintenance Requirements/Original Facilities are Inadequate

1. Increased maintenance staff – Control Maintenance from 140 to 209, Mechanical Maintenance from 135 to 195, and Inspection Maintenance Services (IMS) personnel from 0 to 30. Maintenance staff has increased by > 160 personnel since plant was commissioned.
2. Maintenance strategy is now being focused on day crews as opposed to shift crews. Hence, the total accumulated crew size to be accommodated on days has increased from 40 to 188 maintenance personnel.
3. IMS was never originally provided space for permanent shops and offices. They had been housed in the PHA but this building has been since vacated and condemned.
4. Offices and shops had been built in the path of a potential secondary side pipe failure. These shops were removed and this has resulted in some work groups having inadequate offices and labs. Reference TOE 98-01234-20100-3981-01.
5. Some of the existing shops and offices do not meet the National Building Code and/or ASHRAE 62.1 standards. These areas include MM M&TE lab, CM M&TE lab, MM/CM Valve shop, MM RV shop, MM Seal Lapping shop, and MM Supervisors offices.
6. CM/MM M&TE labs do not have adequate humidity and temperature control. This results in these labs being unavailable for certain critical calibration activities ~ 30% of the time.
7. Greater emphasis on safety resulting in the following requirements:
   a. Pre-job briefing spaces.
   b. Rehearsal and Mockup areas for both IMS and Reactor Maintenance work to maximize efficiency & minimize potential outage delays.
8. Computers now play an important role in delivering work instructions, providing additional information and documenting the work. Hence, offices facilities and computer work stations are required to house them.
9. Changing technologies resulting in the requirement for specialized crews' complete with customized shop space and required FLM/FLMAs such as Fix-It-Now crews and Predictive Maintenance crews.

10. As a result of DNGS progressing through its life cycle, the original plant facilities did not adequately accommodate or foresee current aging plant considerations or license requirements. These considerations include:
    a. Maintenance strategy implementing transition from corrective to preventative/predictive maintenance requires as per industry benchmarking experience a 30% increase in required shop space. Overhaul/refurbishment programs for major breakers, pumps, and valves have or are being developed as part of this strategy.
    b. Space for IMS Quality Control labs and personnel.
    c. IMS Periodic Inspections Programs.
    d. Reactor Maintenance - specialized component repair programs for Pressure Tubes and End Fittings, Feeders, Horizontal and Vertical Flux Detectors, and Adjustor Rods.
11. No provision for adequate Breaker and Relay maintenance. This is currently being performed in the Sequence Event Monitoring computer rooms which were never designed for this purpose.
12. Reactor Maintenance (RM) shop was never provided. Currently RM is housed in a temporary building with inadequate space, no permanent services, and an underrated floor loading capacity.
13. As a result of IMS not having permanent facilities, it takes an extra 2 weeks with 6 people to set up their equipment every outage. IMS also incurred a 2 day outage delay while trying to remove the CIGAR (Channel Inspection and Gauging Apparatus) inspection head from the channel. SCR D-2005-03661 (B3 category). This can be attributed to the lack of proper facilities to do maintenance and rehearsal on CIGAR.

Refurbishment/Upgrade

As part of the 2006 ASL study, a review of the feasibility and cost of upgrading existing ships and offices was performed as a potential option for building a new facility. The following areas were not considered for upgrade as they do not currently exist or exist in an area that was not originally intended for its current use:

- Reactor Maintenance Shop
- CM Breaker and Relay Maintenance Shop
- IMS QA Group
- IMS Pressure Group Inspection Program
- Civil Maintenance FLM offices

The following areas were considered for upgrade at an estimated cost of $33.5M:

- CM M&TE Lab - $4M
- MM M&TE Lab - $5.45M
- CM Valve Shop - $6.3M
- MM RV Shop - $6.46M
- MM Seal Lapping Shop - $6.65M
- MM FLM offices - $4M
- MM Welding Shop - $750K

Refurbishment of these areas was not recommended by ASL due to high costs as a result of a high level of contingency needed due to the risk of performing modifications in an operating plant. In addition existing plant configuration may place limitations on the level of improvements that can be achieved by upgrades. (i.e. existing Common Service Area (CSA) HVAC system may not support required ASHRAE 62.1 and M&TE clean requirements, precise humidity and temperature control specifications without major improvements)

Contracting Out Considerations

Contracting out of maintenance services has been briefly investigated by DNGS Maintenance management. However this strategy was never fully developed, documented, or costed out. The following issues are some of the contributing factors:

1. Damage may occur to sensitive equipment if shipping offsite is required.
2. Emergency type situations where 24/7 response is needed may not be available if a contractor is utilized.
3. Costs and delays associated with Unconditional Transfer Permits and security requirements when shipping offsite and outside the protected area.

The contracting out of major breaker maintenance as part of the OPEX and EPRI recommended developed overhaul program was quoted as $10K per breaker in 2005 which equates to 980 breakers x $10K = $9.8M. This would be required for all 980 breakers on a 12 year cycle. This has not been implemented to date as pilot contracts (both onsite and offsite) were not successful due to quality and timeliness of contract work.

Combined Facilities

Wardrop as part of the 2005 conceptual study was commissioned to assess the viability of an OPG shared site facility. Due to the major decisions pertaining to Pickering A U2/U3 Safe Storage and the pending decision in 2009 for Pickering B refurbishment, this assessment could not be completed and ultimately it was decided by the CNO in 2006 that a combined site maintenance strategy was not viable at this time and the project mandate was changed to a Darlington only project.

DNGS Maintenance has recently investigated preliminarily a combined PNGS/DNGS offsite MM/CM M&TE lab option with OPG Real Estate Services Division and received a quote for $1M for a "leased permanent" fully customized build to suit industrial unit plus $400k per year on a lease agreement. Alternatively a quote of $400k was received for a "leased portable" prefabricated relocatable M&TE lab structure that could be placed in an industrial unit which would then also require a ~ $180k yearly lease cost. These estimates are only for the space and do not include any other costs such as equipment, utilities, IT, etc. or the costs in transporting the tools offsite from both sites on a daily basis under Radiological Transfer Permits. This simplistically works out to a cumulative cost of $9M for the customized build or $4M for the prefabricated relocatable lab assuming a 20 year lease. The proportional cost of the M&TE labs based on the estimated 2410 ft^2 net of new ~ 60,000 ft^2 Maintenance Facility is ~ $1.8M. These costs have not been vetted through by the consultants and have been reflected here to facilitate option comparison.

Hybrid Solution

As part of the 2006 ASL study, a hybrid solution was considered. A hybrid solution consisting of refurbishment of existing lab/shops combined with a new facility was never developed as an option due to the estimated cost for refurbishment for existing areas of $33.6M. This $33.6M combined with the cost associated for a new ~ 25,000 sq. ft building for the remaining areas would have seen cost estimates easily exceeding $55M - $60M before contingency. As a result of these costs this option was deemed prohibitive from a cost perspective and not evaluated any further.

Additional Background and Issues

The ASL cost estimates are only for the construction of the new Maintenance Facility and required building services. The cost of computers, modular office furniture, and telephones are included but as these costs cannot be capitalized along with the building they will be accounted as minor fixed assets in subsequent BCS's. The cost estimates do not include any costs such as: moving existing maintenance equipment, purchase of new maintenance equipment, radiation monitoring equipment, signage, etc.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Incremental Cost	Alt 2 Delay	Alt 3 MF Option H	Alt 4 MF Option I	Alt 5
Revenue							
OM&A	-	(1,600)			(1,244)	(1,244)	
Capital	-	(54,543)			(47,416)	(45,527)	
NPV (after tax)	(150,699)	(99,238)			(100,491)	(108,252)	
Impact on Economic Value (IEV)	N/A	51,461			50,208	42,447	
IRR%	N/A	13.4%					
Discounted Payback (Yrs)	N/A						

Status Quo - Not Recommended
This option is not recommended since the need for upgraded maintenance facilities at Darlington was first identified in 2002, and has escalated since. The risks to employee health and safety, potential outage extension, and loss of productivity would continue to rise incrementally.

Alternative 1 - Maintenance Facility Layout G from Revised Conceptual Study - Recommended

Option Comparison	Option G	Option H	Option I
CM M&TE Lab	✓	Excluded	Excluded
MM M&TE Lab	✓	Excluded	Excluded
MM Relief Valve Shop	✓	Excluded	Excluded
MM Seal Lapping Shop	✓	✓	Excluded
Reactor Maintenance Shop	✓	✓	✓
CM Breaker Maintenance Shop	✓	✓	✓
CM/MM Valve Shop	✓	✓	✓
IMS Pressure Tube Area	✓	✓	✓
IMS QC Labs & Offices	✓	✓	✓
Civil FLM Offices	✓	✓	✓
MM FLM Offices	✓	✓	✓
MM Welding Shop	Excluded	Excluded	Excluded

Proceed with the scope defined in the revised Conceptual Study Option G by ASL with a space estimate of 57,300+ sq. ft at a cost estimate o[redacted]excluding contingency. This alternative will address all the areas identified in the revised Charter except the welding shop. The new facility will increase maintenance productivity and effectiveness, mitigate the potential increase of industrial accidents, mitigate potential outage extensions, and potential future cost savings realized by not moving labs/shops permanently offsite into a leased industrial space. The scope of this recommended option based on the priority specified by the sponsor will consist of the identified shops, labs and offices above under Option G. This alternative has a positive NPV of 54.4M$. See Attachment E for a breakdown of this NPV.

Alternative 2 - Delay Project - Not Recommended
N/A

Alternative 3 – Maintenance Facility Layout H with "leased portable" M&TE lab - Not Recommended
This option provides a new facility similar to Layout G with the exclusion of the CM and MM M&TE labs, and MM Relief Valve shop. The space estimate for this option is 48,900+ sq. ft. and the cost estimate associated with this alternative is ~ $39M excluding contingency. This option does not effectively meet all the current and identified future DNGS Maintenance needs and will result in further management intervention to mitigate the needs of these excluded areas in the future.
NPV was calculated including the purchase of a $400K relocatable CM/MM M&TE lab plus an estimated industrial lease cost of $180K per year. These estimates are preliminary and only for the space and do not include any costs such as equipment, utilities, IT, etc. or the accurate costs in transporting the tools offsite from both sites on a daily basis under Radiological Transfer Permits.

Alternative 4 – Maintenance Facility Layout I with "leased portable" M&TE lab - Not Recommended
This option provides a new facility similar to Layout H with the further exclusion of the MM Seal Lapping shop. The space estimate for this option is 45,500+ sq. ft. and the cost estimate associated with this alternative is ~ $37.4M excluding contingency. This option does not effectively meet all the current and identified future DNGS Maintenance needs and will result in further management intervention to mitigate the needs of these excluded areas in the future.
NPV was calculated including the purchase of a $400K relocatable CM/MM M&TE lab plus an estimated industrial lease cost of $180K per year. These estimates are preliminary and only for the space and do not include any costs such as equipment, utilities, IT, etc. or the accurate costs in transporting the tools offsite from both sites on a daily basis under Radiological Transfer Permits.

Alternative 5 – N/A - Not Recommended

4/ THE PROPOSAL

The Following are the objectives and deliverables for this Partial BCS:

Building Removal & Decommissioning
- Completion of Detailed Design.
- Preparation of decommissioning workplans.
- Issue PO for the decommissioning and removal of buildings.
- Completion of contract for the decommissioning and removal of buildings
- AFS for the building removal and decommissioning

Relocate Buried Services and Establish Tie-In Points
- Issue PO for Detailed Design.
- Complete Detailed Engineering of the Tie-Ins and Buried Services relocations
- Issue Request for Proposal (RFP) and evaluate bids for an installation contract.
- Preparation of workplans.

Maintenance Facility
- Preparation of an EPC contract for the construction of the new Maintenance Facility.
- Issue a RFP for a Commercial EPC contract for the new Maintenance Facility
- Receive bids from proponents and complete bid evaluations
- Issue a PO for the Preliminary Design of the Maintenance Facility
- Issuance of a Full Release BCS.

In the Full Release BCS the following items will be included as per Nuclear Oversight Committee/Board of Directors specific request:

1. Analysis of existing space currently used by Maintenance staff for the various functions and an explanation of why each function must be moved to the new location (eg, tabulate: function/space currently used for this function/why the function must be moved to a new location).

2. Detailed benchmarking data for similar building construction on a cost-per-square foot basis.

5/ QUALITATIVE FACTORS

The successful completion of this project will improve the following:

Staff relations
- New maintenance facility shops and offices will relieve overcrowding and congestion and result in improved staff morale.

Health and Safety
- New maintenance facility shall be compliant with ASHRAE 62.1 air quality requirements, relieve overcrowding and congestion, and result in improved health and safety inefficiencies.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Overall project cost exceeds current estimate. Current cost estimates are conceptual. Cost estimate accuracy is +60%/-25%	Potential adjustment required on scope and cost of the project.	High	The conceptual study layouts have been independantly cost estimated by an external 3rd party estimator Altus Helyar. Construction quote can be obtained after detailed design for the Full Release BCS. A second independent cost estimate will be commissioned when the scope is more defined before the Full Release BCS.	Medium
Changes to the funding release strategy and/or fine tuning of contracting stategy may impact overall cost and schedule (owner only vs owner constructor) This is a 1st time strategy for implementing an owner only contract inside the protected area. Lessons Learned can be utilized for future projects that may result in schedule and cost savings.	Could cause a delay to the schedule & increase costs.	Medium	Review and finalize contracting stategy and impact to design and installation requirements with Supply Chain, Procurement, Design & Legal before Full Release BCS is issued. The estimates used for this BCS were conservatively assumed to be Owner/Constructor contracts. Early involvement of serior station management in investigating contracting strategy.	Medium

Cost for demolition of Power House Annex exceeds conceptual estimate of $2.0M due to: - Impact on adjacent building - Waste removal and recycling requirements - Cost for the design and installation for the relocation of underground services and building service tie-ins exceeds conceptual estimate	Potential increase in scope and cost of project.	**Medium**	Cost to remove the PHA was estimated by ASL in the 2006 conceptual study. Impact to other affected structures due to removal of the PHA has been identified and mitigation discussed with Sponsor. Sponsor has concurred that removal of adjacent trailers at this time is a cost effective solution. Waste removal and recycling plan being developed. [redacted] contingency added in 2008 cash flow to cover potential added cost of waste removal. Cost to complete the relocation of underground services and building tie-ins was estimated by ASL in the 2006 conceptual study. A drawing reivew was completed to identify underground services in the area during the conceptual study	**Medium**
Scope				
Final scope of the new Maintenance Facility may require further cuts due to OPG budget constraints.	Further changes in scope will delay the schedule and increase OPG project management costs.	**High**	A Detailed design will be performed to identify the detailed scope of buried services, and tie-ins before the scope is finalized for the Full Release BCS. A more accurate cost estimate will be available in the next release for management decision making.	**Low**
Preliminary/Detailed Design may result in an increase in scope.	Changes in scope will delay the schedule and add cost to the project.	**High**	Further scope identified during the design will be challenged by projects & have to be agreed by all stakeholders & sponsor.	**Medium**
Increase scope of work due to discovery work (ie re-route buried services in building footprint).	Increase in cost and schedule or further reduction in shop space to ensure approved budget is maintained.	**High**	Preliminary drawing review has been conducted to identify any possible services that may require relocation. Field survey to be completed during Technical Evaluation.	**Medium**

Schedule				
Insufficient information to determine the scope and timeline of design deliverables accurately.	Increase in cost and schedule.	**Medium**	Fine tuning of Detailed Design deliverables will be completed after Technical Evaluation and included in subsequent RFPs for Buried Service relocation, Maintenance Facility construction, Building service and plant system tie-ins etc. These will be detailed in subsequent BCS's.	**Medium**
Fine tuning of contracting stategy may impact overall cost and schedule.	Require changes to funding release strategy which could cause a delay to the schedule & costs.	**High**	Review and finalize contracting stategy and design and installation requirements with Supply Chain, Procurement, Design & Legal before the Full Release BCS is issued.	**Medium**
Design deliverables not on time.	Delay to schedule.	**Medium**	Select approved vendor, provide clear scope & deliverables. Review progress regularly & establish and monitor effective design performance metrics.	**Low**
Resources				
Insufficient OPG design resources available.	Delay project schedule & milestones.	**High**	Design will be contracted out to external agency. OPG Projects Design have committed to provide DTL and any additional design support for this project.	**Low**
Availablility of qualified vendors to perform design and subsequent implementation (procure, construct).	Delay in issuing contract due to need to assess various interfacing risks, vendor qualification issues, and contracting language.	**Medium**	Obtain OPEX from other OPG projects of similar nature. Early involvement with Supply Chain and various other departments or potential vendors and early review of the associated contracting strategies. Supply chain is currently in the process of qualifying more vendors for N286.1 "procurement".	**Medium**
Technical				
Legacy issues on Design.	Re-engineering may be required if there are legacy and interface issues with systems that the project is modifying. This would add scope to the project which may cause delays and increase	**Medium**	Preliminary site walkdowns have been completed. Complete drawing review on systems being impacted to be performed during Technical Evaluation and subsequent Engineering efforts.	**Low**

	project costs.			
Discoveries from geotechnical analysis of soil.	Delay and added cost to the project due to the prefered site not being suitable for building addition which could then subsequently lead to Increased costs to the design and installation to meet the requirements identified.	**Medium**	Test drill site to determine the soil composition prior to completing Technical Evaluation to ensure the design takes this into account. Method & cost to implement corrective actions will be challenged & documented.	**Low**
Regulatory				
There are no regulatory risks.		**N/A**		**N/A**
Environmental				
Excavation and Construction waste may not be suitable for shipment to a clean landfill site due to radiological contamination.	Added cost to the project due to disposal costs associated with contaminated waste.	**Low**	A Geotechnical Analysis and Radiological testing by Kinetrics will be performed during the Technical Evaluation. A Waste Disposal plan will also be developed and submitted to OPG for acceptance.	**Low**
Waste from demolition of buildings may not be suitable for recycling or for shipment to a clean landfill site due to radiological and/or conventional contamination.	Added cost to the project due to disposal costs associated with contaminated waste.	**Low**	All building material to be scanned and tested for radiological, asbestos, mold and other contaimination prior to demolition of buildings	**Low**
Health & Safety				
Personnel injured during demolition of buildings.	Personnel injury or death Delay to project	**Low**	Adherence to OPG Policies and Procedures will be maniditory during the removal of buildings. Contractor's safety record wil be part of the criteria during bid evaluation.	**Low**
Asbestos, mold or other conventional hazardos material present in the buildings to be removed.	Personnel injury or long term health concerns. Added costs and/or delay to project.	**Low**	All building material to be scanned and tested for asbestos, mold and other contaimination prior to demolition of buildings. Ensure personnel protect themselves with the apporpriate PPE per OPG Policies and Procedures	**Low**

Investment				
Cost benefit information cannot justify proceding with the project. The final scope of the what that is to be included in the maintenance facility is not yet known.	Return on investment cannot be realized.	**Medium**	End users have been interviewed to gather critical data for calculation of the NPV. Investment Finance and Station Long Range Strategic group will further scrutinize validity of assumptions for the next release based on the final scope decision after the Technical Evaluation is complete	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
TBD in Next Release	TBD in Next Release	TBD in Next Release	

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

BCS	Business Case Summary
PHA	Power House Annex
RFP	Request For Proposal
EPC	Engineer, Procure, Construct
IMS	Inspection Maintenance Services
TOE	Technical Operability Evaluation
QC	Quality Control
CIGAR	Channel Inspection and Gauging Apparatus
SCR	Station Condition Report
ASL	Acres Sargent & Lundy
NPV	Net Present Value
CM	Control Maintenance
PO	Purchase Order
DTL	Design Team Leader
OPEX	Operating Experience
TBD	To Be Determined
PIR	Project Implementation Report
PWU	Power Workers Union
BTU	Building Trades Union
PEP	Project Execution Plan
AFS	Available For Service
IEV	Impact On Ec Value
IRR	Internal Rate of Return
RM	Reactor Maintenance

Appendix "B" Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2007	2008	2009	2010	2011	2012	2013	Later	Total
Developmental	Jul	2007	1,369	234							1,603
Partial			(861)	3,960	3,836						6,935
Full			508	4,194	18,932	19,985	13,599	521			57,739
											0
											0
											0
											0
											0

LTD Spent	Dec	2007		508							508

Comments:
Previous release of $450k was obtained in 2002 to provide seed money for the first Acres Sargent & Lundy conceptual study of which $116k was spent. $34k in capital interest charges has accumulated against this amount to date.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

-
- OPG staff will provide project management & support role during design and implementation
- Design and Installation work will be performed by contractors with oversight and support for OPG Project Design
- Current P3 resource costs were used thru 2009. Escalation rate of 4% was used for 2010 & 2011
- DNGS Strategic Planning has prepared a Monte Carlo Crystal Ball risk model analysis of all alternatives to develop the NPV figures. All assumptions used for this model were based on ASL submissions, OPG reliable sources, or from individual area stakeholders. Attachment D has the relevant information from this analysis for the recommended Option G with an overview of the NPV figures for Base and Options H and I. The appendix also includes the assumptions, Long Term Disability statistics. This model has been reviewed and accepted by OPGN Investment Management for the purpose of the Economic Analysis values used for this Developmental BCS.

Financial Assumptions:

- 7% discount rate
- PHA cost of removal will be expensed to accumulated depreciation monthly as incurred.
- Maintenance Facility Design and Construction costs were estimated by ASL with the assistance of an external constructor Ball Construction. A [redacted] additional premium was added over equivalent commercial costs due to the fact that this work is inside the DNGS protected area and subject to OPG ECC processes and Safety Regulations. OPG Project Management and Support costs were developed between ASL & OPG Design Projects and substantiated via an independent 3rd Party estimator Altus Helyar.
- See Attachment "D" for BCS NPV Assumptions and Analysis.
- Note that this project estimate does not include costs for moving existing maintenance equipment, purchase of new maintenance equipment, purchase of radiation monitoring equipment

Project / Station End of Life Assumptions:

- Darlington end of life ~ 2050
- Maintenance Facility nominal end of life 2050

Energy Price / Production Assumptions:

- See Attachment "D" for BCS NPV Assumptions and Analysis

Operating Cost Assumptions:

- See Attachment "D" for BCS NPV Assumptions and Analysis

Other Assumptions:

- OPG to provide unrestricted access to work area
- All work is within the secured area with incumbent restrictions

Project Name 16 - 31717

Partial Release Business Case Summary D-BCS-28200-10003-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Yr	This Release 2008	This Release 2009	Future Release 2009	Future Release 2010	Future Release 2011	Future Release 2012	Later	Total
Project Management (OPG)	164	570	356	357	875	484	184		2,990
Engineering & Drafting (OPG)	54	325	190	190	175	190	117		1,241
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	**508**	**4,194**	**3,836**	**15,096**	**19,985**	**13,599**	**521**	**-**	**57,739**
2008-2012 Business Plan	1,170	2,140	2,951	11,418	15,154	11,556	-		44,389
Variance to Business Plan	**(662)**	**1,105**	**-**	**194**	**219**	**(1,095)**	**401**	**-**	**162**
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	**508**	**3,245**	**2,951**	**11,612**	**15,373**	**10,461**	**401**	**-**	**44,551**
Total Release (incl contingency)	**508**	**4,194**	**3,836**	**15,096**	**19,985**	**13,599**	**521**	**-**	**57,739**
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)	**137**	**1,463**							**1,600**

Basis of Estimate					
Design Complete	Zero to Minimal		Quality of Estimate	Conceptual + 60% to - 25%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	N/A
Reviewed by Sponsor	Yes	Budgetary Quote(s)	No	Phase 1 Actual Used	No
Similar Projects	No	Contracts in place	No	Competitive Bid	No

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF is not required .

Reviewed By:

[signature] 4 Feb 2008

Stephanie Tham
Project Manager
Date:

Approved By:

[signature] Feb. 4/08

Dianne Gaine
Eng & Mods Manager (Strat IV)
Date:

Project Name 16 - 31717

Partial Release Business Case Summary D-BCS-28200-10003-R000

Attachment "B" **Project Variance Analysis**

Capital	LTD Dec 2007	Choose One Last BCS Jul 2007	This BCS Jan 2008	Variance	Comments
Project Management (OPG)	164	2602	2990	388	Add resources for 2012 project closeout
Engineering & Drafting (OPG)	54	888	1141	253	Add resources for 2012 project closeout
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	**508**	**57701**	**57739**	38	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**508**	**57701**	**57739**	**38**	
Total Release (excl contingency)	**508**	**44420**	**44551**	**131**	

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
18	Apr	2008	PHA DCP Approved
21	Jul	2008	Work package Assessment complete - PHA Demo.
07	Oct	2008	Start of PHA Demolition
07	Feb	2009	AFS PHA Demolition
16	Apr	2008	RSTI Design Contract PO Issued
05	Aug	2008	RSTI Preliminary Design Complete
10	Dec	2008	RSTI DCP Approved
15	Apr	2009	RSTI Work Package Assessment Complete
19	June	2009	Full Release BCS Approved

A Project Execution Plan (PEP) will be approved by Jun 2009

Comments:

Attachment "D"

DNGS Long Range Planning - Recommended Option NPV Calculation

- Result Summary
- Assumptions
- LTA source assumption
- Individual area results

NPV Option Result Summary

Up to Retube - 2021	NPV (k$)
Base Case	(67,274)
Option G	(67,430)
Option H (with leased Portable M&TE lab)	(64,482)
Option I (with leased Portable M&TE lab)	(67,250)

After Retube - 2050	NPV (k$)
Base Case	(150,699)
Option G	(99,283)
Option H (with leased Portable M&TE lab)	(100,490)
Option I (with leased Portable M&TE lab)	(108,251)

Attachment E

Briefing Note: 31717 DNGS Maintenance Facility
Breakdown of the 54M$ Preferred Alternative NPV

		%		NPV (M$)
Backlog Improvement (1)		3.5		1.8
LTA Reduction (2)		0.1		0.1
Productivity Gain (3)		13.1		6.7
Planned Outage extension reduction (4)				28.8
- Reactor maintenance shops	27%			
- IMS Pressure Tube Insp prog	10%			
- MC Valve shop	10%			
- Other shops	9%			
subtotal	56%	56.0		
Forced Outage extension reduction (5)				11.6
- IMS Quality group	8%			
- MC Breaker & Relay shop	7%			
- Other shops	8%			
subtotal	23%	22.6		
Rebuilding, not buying, Seal parts (6)		2.0		1.0
Breaker overhaul inhouse (7) & various other		2.6		1.3
		100.0		51.4

(1) Online Elective Maintenance Backlog improvement will reduce Forced Loss Rate which will impact on generation and incremental Forced Outage Cost.

(2) Existing facilities are overcrowded and noisy with poor air quality which may cause potential Health and Safety incidents.

(3) Overcrowded locations, lack of Pre-Job Briefing areas, lack of crane equipment, extra equipment shuffling, lack of Mockup/Rehearsal area, and insufficient temperature/humidity control resulting in overtime to recover productivity losses.

(4) Improve response time on tool calibration, breaker preparation, valve work, Channel Inspection and Guaging Apparatus for Reactor work, Single Channel Fuel Replacement work, and minimize delays as the Mockup/Rehearsal facility and crane are always in place.

(5) Improve response time on tool calibration, Release Valve decontamination, Seal preparation, breaker preparation, Channel Inspection and Guaging Apparatus for Reactor work, and minimize delays as the Mockup/Rehearsal facility and crane are always in place.

(6) Facility to rebuild old Seal parts instead of buying new ones will result in significant savings.

(7) Performing major breaker maintenance in house instead of outsourcing.

DNGS Construction Change Room 16 - 31718

Full Release Business Case Summary D-BCS-28200-10004-R001

1/ RECOMMENDATION:

Approval is requested for this Full Release for a total 23,781 K$ Capital, contingency) to complete both the construction of a new Construction Change Room (CCR) c/w Lunchroom facility and the removal of the old CCR. The new CCR is being constructed in time to support the March 2009 Vacuum Building Outage (VBO) at Darlington.

The objective of this project is to construct a new CCR for DNGS maintenance and contract staff to provide a safe and effective work environment, and then to decommission and remove the existing CCR. The new CCR will have an increased capacity over the previous change room, which will relieve overcrowding and congestion, thereby improving current health and safety inefficiencies.

A firm fixed price contract is in place for the construction of the new CCR. The Project has obtained a contractor budgetary quote for the removal of the old CCR based on applicable approved and accepted design packages.

This project is being executed in several phases between 2007 and 2010:

- 2007/2008 – Detailed Design has been completed
- 2008/2009 – Construction of new CCR and turnover to OPG Operations & Maintenance
- 2009 – Removal and decommissioning of existing CCR / prepare Design for fire alarm signal integration
- 2010 – Field installation of fire alarm signal / Project close-out

The timeline for the completion of the new change room is extremely tight. Full station management support, including exemption from certain activity milestones in station work processes, is required to adhere to the schedule as planned.

A Partial Release of 13,304 K$ had been approved in March 2008 indicating a total project cost of $16,020 K$. Since then the cost estimate has increased primarily due to an increase in the construction costs based on the completed design package, the project having to complete multiple parallel activities and field discovery work.
A station contingency plan should be available for the 2009 VBO to mitigate contractor change facility needs should this project be delayed.
Ongoing negotiations with the CNSC are still progressing to limit the scope of new fire protection work required to meet the new nuclear fire code CSA N293-07. There is a risk that the CNSC may require a fire suppression system to be installed in the new CCR. This would have to be completed after the VBO and would be an impact to the cost of the project.

$000's (incl contingency)	Funding	LTD 2008	2009	2010				Later	Total
Currently Released	Partial	12,622	2,312						**14,934**
Requested Now	Full	901	6,692	1,254					**8,847**
Future Funding Req'd									**-**
Total Project Costs		**13,523**	**9,004**	**1,254**	**-**	**-**	**-**	**-**	**23,781**
Other Costs									**-**
Ongoing Costs									**-**
Grand Total		**13,523**	**9,004**	**1,254**	**-**	**-**	**-**	**-**	**23,781**
Investment Type Sustaining		**Class** Capital		**(IEV) Impact on Ec Value** -0.8M$		**IRR**		**Discounted Payback** N/A	

Submitted By:

Wayne Robbins 2009-01-30
Wayne Robbins Date:
Site VP, Darlington

Finance Approval:

Donn Hanbidge Date:
SVP & CFO

Line Approval (Per OAR Element 1.1 Project in Budget):

Jim Hankinson Mar 6/09
Jim Hankinson Date:
President & CEO

2/ BACKGROUND & ISSUES

The existing CCR was installed in the early 1990's and is nearing its end of useful life nominally rated at a maximum of 20 years for a mobile type building design. This facility was not designed for its current capacity and hence is congested and inefficient when utilized at or near capacity during outages and major projects. The Design Agency that performed the Conceptual Study for the new Maintenance Facility and new CCR had recommended that a new change room be constructed instead of relocating or refurbishing the existing CCR due to doubt that the existing CCR could survive relocation.

Due to changing work force demographics since DNGS was first built, many of the permanent staff and contractors hired for project and outage work are more regularly women. The current CCR does not have sufficient women's change room facilities. There are insufficient lunchroom facilities to accommodate the required contractor staff to support station activities such as major outages or large projects. The proposed new CCR will be approximately 19,000 sq. ft. and as per the project charter (D-PCH-28200-10002) developed by Darlington Maintenance, the capacity is required to increase from the old CCR as follows:

- Women's change room – from 24 to 150 personnel
- Men's change room – from 450 to 500 personnel
- Lunchroom – from 125 to 225 personnel fixed seating capacity

The expected occupancy level of the new CCR is 100 – 150 people during low periods, and 350 – 500 people during peak (unit outage) periods. The timeline for peak periods is about one month prior to an outage to the end of the outage, based on a 3 month planned outage. These capacity estimates were provided by the DNGS Contract Management Office (CMO) and are based upon the current occupancy of the existing CCR and the current outage schedule at Darlington.

A Design Agency was commissioned to perform a conceptual study on the project. The design agent provided one conceptual layout and three cost estimates for the different construction methods selected to provide a permanent CCR in the most cost effective and expeditious manner to meet our tight timeline. The construction options provided by the design agent are "Modular", "Relocatable", and "Mobile".

- The "Modular" building would be constructed as uniform structure throughout. It would be constructed on site using prefabricated wall sections, which would provide better control of quality and specification compliance at all phases of construction.
- The "Relocatable" building would be assembled on site from prefabricated structures that are built, cut and transported in large sections from the manufacturing site. However this would not allow full quality control and specification compliance on the construction site. The sections joints would be sealed, and depending on the quality of seals installation, the structure may be susceptible to leaks.
- The "Mobile" building would also be assembled onsite; however it would consist of prefabricated trailers attached together to meet OPG's specification. This is the preferred option.

The "Mobile" building design selected for the change room has a life span of approximately 20 years and will be able to support maintenance activities for DNGS beyond the current expected end of life of 2018 to approximately 2029. Decisions will need to be made in regards to continuing maintenance costs to extend the mobile CCR life beyond its expected 20 year lifespan.

The new CCR is required to be completed before the start of the DNGS 2009 Vacuum Building Outage (VBO) and the demolition and decommissioning of the existing CCR will be scheduled after the 2009 VBO Outage. The basis for this time frame is to ensure both the old and new Construction Change Rooms are available to facilitate the expected large influx of contract staff during the 2009 VBO Outage.

Approval has been obtained from the Director of Operations & Maintenance for the project to be exempt from Integrated On-line Work Scheduling per N-PROC-MA-0022. However, it is the intent of the project to follow N-PROC-MA-0022 to the extent possible.

Ongoing discussions have been taking place with the CNSC to seek concurrence for our proposed alternative solution to meeting the new nuclear fire code CSA N293-07. It has been agreed that the migration of the fire alarm signal to the Main Control Room work can be implemented after the partial AFS in order to not jeopardize the availability of the new CCR for the 2009 VBO. An additional risk pertaining to the requirement for an alternate solution to meeting the new code requirement to install automatic fire suppression has been added under specific contingency, (installation of smoke exhaust).

Current Project Status

Detailed Design for both the installation of the new CCR and demolition of the old CCR has been completed by a design agent.

Construction contract for the new CCR has been awarded to a construction contractor.

Construction Work Completed for New CCR
- Re-routing of all underground services
- Site Preparation and construction of the foundation
- Fabrication and setting in place of the all 26 CCR modules
- Interconnection of modules is in progress
- Tie-ins to the stations domestic water and sanitary sewer
- Routing of the 4kV power supply cables from the CCR to the station
- Routing of IT cables from the CCR to the Bill Gearing Guardhouse
- Routing of IT cables from the CCR to the Auxiliary Security Building
- Installation of building lightening arrestor system and grounding

Construction Work to be Completed to Meet the March 23rd AFS to Support VBO
- Completion of interconnection of modules
- Installation of exterior stairs & ramps
- Return all roads and walkways to preconstruction condition and construction of new walkways
- Complete tie-ins to Fire Protection System – Alarms
- Complete tie-ins to Security
- Complete installation and station tie of transformer, switch gear, revenue metering & transfer switch
- All testing and commissioning of systems.

Post Partial AFS Work for the New CCR
- Complete all required Engineering Change Control work
- Complete the design and installation to migrate the Fire Alarm Signal from the Main Security Building to the Main Control Room to satisfy CSA code N293-07 prior to March 2010.

Demolition of Old CCR
- Scanning of the building and contents for radiological and conventional hazards (including mold and asbestos)
- Cut and cap all services from the station
- Removal of all internal equipment/material
- Demolition of old CCR and return site to acceptable condition.

A budgetary quote for the decommissioning and removal of the old CCR has been obtained from the construction contractor.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Stop the Project	Alt 1 (Recommended)		Alt 2	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost	Delay			
Revenue							
OM&A	-	(1,015)	(890)				
Capital		(22,221)	(9,068)				
NPV (after tax)	(7,582)	(20,336)	(8,398)				
Impact on Economic Value (IEV)	N/A	(12,754)	(816)				
IRR%	N/A						
Discounted Payback (Yrs)	N/A						

Stop the Project - Not Recommended

This option is not recommended as the projected change room and lunchroom capacity would then not be in place to support the large number of contract staff expected to be onsite during the 2009 VBO. This would also require the station to then develop alternate contingency plans to facilitate the expected large influx of contractors. Furthermore major repair and renovations will have to be considered for the existing change room for it to continue to operate beyond 2009. A new CCR will be required in the future as the existing CCR has gone over its expected useful life and is not expected to survive beyond 2012. The Project has a Life to Date investment of 8,537 K$, (as of Oct 22, 2008), and projects the 2008 year end investment to be $13,792k. The costs associated with a decision to defer or cancel the Project would be significantly higher than the cost to complete as it would have to take into account the penalties to cancel the current contracts, the effort to resurrect the Project at a future date, and the associated inflationary impacts.

Alternative 1 - Complete building a new "Mobile type" CCR and remove existing CCR - Recommended

This option is recommended as a new CCR is required to replace the existing life expired CCR and provide a safe and effective work environment for the next ~ 20 years. The "Mobile" type building option (consisting of pre-fabricated modules) has a manufacturer recommended nominal life of 20 years and will be available to support future maintenance activities should DNGS life extension become a reality to ~ 2029. It will also increase the capacity of the women's change room to address this identified demographic deficiency and provide a larger lunchroom to meet the projected future DNGS contractor needs with regard to outages and large projects as identified by stakeholders. The new CCR will be available to support future outage, project, and VBO maintenance activities. The "Mobile" building meets the requirements of the charter and is the estimated least costly option.

The Project has already completed the re-routing of underground services, the construction of the 26 modular units, and the tying in the domestic water and sanitary sewer services. The major items remaining to be completed prior to the CCR being put into service is the installation of the electrical equipment (2000 KVA transformer, Disconnect, Transfer Switch, and Revenue Metering), completing tie-ins to the station and commissioning activities. The significant life to date investment in this project will be realized once the final services are tied into the building and it is put into service prior to the VBO.

There are significant risks associated with this implementation schedule as the timeline for the completion of the new change room is extremely tight. Future decisions will need to be made in regards to extent of continuing maintenance costs to extend the mobile CCR life beyond its expected 20 year life expectancy.

Alternative 2 - Delay Project - Not Recommended

Alternative 3 – N/A - Not Recommended

Alternative 4 – N/A - Not Recommended

Alternative 5 – N/A - Not Recommended

4/ THE PROPOSAL

The Following are the objectives and deliverables for this Full Release BCS:

- Complete installation of the new CCR
- OPG support for construction of the new CCR
- Partial AFS of new CCR prior to 2009 VBO
- Issue RFP and PO for the decommissioning and removal of the old CCR
- Complete the field work to decommission and remove the old CCR
- 2009/2010 Design and execution for the migration of the Fire Alarm signal from the Main Security Building to Main Control Room to comply with CSA-N293-07
- Final AFS to ensure completion of Engineering Change Control process and full station turn-over
- Closeout of the Project

5/ QUALITATIVE FACTORS

The successful completion of this project will improve the following:

Staff Relations

- New larger capacity change rooms and a lunchroom which will relieve overcrowding and congestion and result in improved staff morale.

Health and Safety

- Increased site capacity of DNGS women's change room to reflect changing demographics to ensure compliance with Occupational Health and Safety requirements.
- New improved larger capacity change rooms and lunchroom will relieve overcrowding and congestion and hence improve health and safety inefficiencies.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Cost for demolition of existing CCR exceeds the contractor estimate of $420K	Potential increase in cost of the project	**Low**	Cost to remove the CCR was derived by a budgetary quote by a Constructor upon completion of detailed design of the CCR demolition	**Low**
Actual cost for design and installation of fire alarm signal migration exceeds current estimate	Increase cost to the project	**High**	Performed preliminary walkdown with contractor and design agent Budget estimate for design portion obtained	**Medium**
Permanent power supply from the station not installed in time for Partial AFS	Must provide temporary power in the form of generators for operation during the VBO & D931 (est. $300k/month)	**Medium**	Specific contingency money included in project cost estimate	**Low**
Delay in the delivery of electrical equipment and design package may lead to the need to shorten execution timeframe.	Increase in cost	**High**	Premium paid to expedite delivery of equipment. Bi-Weekly meeting with vendor Weekly meeting with design agency frequent dialogue with contractor WARR design package issued to run cables	**medium**
Scope				
*** Cost, Scope and Schedule Risk *** Limited Implementation timeline could result in discovery items in construction	Potential increase in the cost, scope and schedule of the project	**Medium**	-Close involvement with constructor and design agency during both design and installation phases -Mitigation actions to be considered for outstanding items for partial AFS	**Low**
Requirement to install a sprinkler system in the new CCR to meet the new fire code	Significant impact to Project cost and schedule. Installation would have to be executed while Change Room was in service which would have further negative impact.	**high**	Ongoing discussions with the CNSC Utilize third party fire consultant to propose alternate solution to installing sprinklers Engage senior level management in the station as part of the resolution process	**medium**

Schedule				
Overall schedule is too tight to complete implementation of the new CCR	Inadequate change room facilities available to support DNGS VBO	**Medium**	-Current constructor installation schedule demonstrate AFS date can be met -Management support required for exemption from certain milestones for work processes	**Low**
Discovery field issues may jeopardize project schedule	Delay to project	**Medium**	Contractor working extended hours to maintain schedule	**Low**
Requirement to keep the existing CCR in service beyond the current scheduled demolition date may effect the estimate for the demolition of the existing CCR	Increase duration of the project and extend final AFS date	**Medium**	Inform station stakeholders of impact on cost and schdeule to this project.	**Low**
Resources				
Availability of contractors to support commissioning	Delay commissioning and AFS of the CCR	**Low**	Ensure Service contracts in place with vendors to support commissioning	
Technical				
CCR fails one or more commissioning requirements	The time to correct any deficiencies discovered may delay commissioning and AFS of the CCR	**Low**	Detailed Commissioning Specification issued and commissioning workplan to be reviewed and approved by stakeholders	
Regulatory				
Inability to secure CNSC's concurrance for alternative solution to meet N293-07	Significant cost increase to retrofit fire protection system back into the new CCR	**High**	Engage third party fire consultant to propose alternate solution to fire suppression system Secured CNSC's concurrence on a number of deviations Ongoing senior level discussions between OPG and CNSC to seek resolution Specific contingency of $500k added for the installation of a smoke exhaust system	**medium**
Environmental				
Hazardous materials may be present in existing life-expired	Waste Disposal could have environmental impact	**Low**	Waste Disposal Plan has been developed by Design Agency to ensure proper disposal of	**Low**

CCR			all material as per OPG guidelines.	
Health & Safety				
Hazardous materials may be present in existing life-expired CCR	Health and Safety Hazards are possible (Asbestos, PCBs, mold etc.)	**Medium**	-All health and safety hazards will be identifed, as testing and analysis will be performed on the existing CCR materials prior to demolition by Conventional Safety.	**Low**
Investment				
Cost benefit information cannot justify proceeding with the project.	Value of invested capital not fully realized	**Medium**	-Engage investment finance and long term strategic planning group in reviewing cost and benefit calculation -Clear identification of cost and benefits of new CCR -Seek cost efficiency in both design and construction phases	**Medium**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Comprehensive	Jan 2010	Dec 2010	Director, Operations and Maintenance

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Construction of new CCR	Not in service	New building will be available in time to support VBO	Successful Partial AFS	DNGS Maintenance
2.	Demolition of existing CCR	In Service	Demolition complete following D931	Successful AFS	DNGS Maintenance
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

Acronyms

BCS	Business Case Summary
CCR	Construction Change Room
PHA	Power House Annex
RFP	Request For Proposal
QC	Quality Control
SCR	Station Condition Report
ASL	Acres Sargent and Lundy
NPV	Net Present Value
CM	Control Maintenance
PO	Purchase Order
DTL	Design Team Leader
OPEX	Operating Experience
LLM	Long Lead Material
TBD	To Be Determined
PIR	Project Implementation Report
PWU	Power Workers Union
VBO	Vacuum Building Outage
BTU	Building Trades Union
PEP	Project Execution Plan
AFS	Available For Service
IEV	Impact On Economic Value
IRR	Internal Rate of Return

Appendix "B" Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	**Month**	**Year**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**Later**	**Total**
Developmental	Jul	2007		1,204	426						1,630
Partial	Feb	2008		(693)	11,685	2,312					13,304
Full	Dec	2008			13,523	9,004	1,254				23,781
											0
											0
											0
											0
											0
LTD Spent	Oct	2008		511	8,026						8,537

Comments:

PCRAF approved in September 2008 to release $2.2M of contingency funding.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

- OPG staff will provide project management and support role during design and implementation
- Design and Installation work will be performed by contractors
- Estimated costs include utility tie-ins.

Financial Assumptions:

- Current P3 resource costs were used thru 2009. Escalation rate of 3% was used for 2010 and 2011

Project / Station End of Life Assumptions:

- Darlington end of life ~ 2018, *(2040+ with refurbishment)*

Energy Price / Production Assumptions:

Operating Cost Assumptions:

- Additional ongoing Utility costs new CCR to old CCR:
  - A design agency calculated Delta of 100KW electrical consumption - Current Energy Cost of $0.0466/kWh @ escalation rate of 2% per annum.
  - A design agency calculated Delta of 27,000 ft3 water consumption - Current Regional Municipality of Durham rate of consumption of $0.437/m3 @ escalation rate of 2% per annum.

- Any extra janitorial costs have not been included.

Other Assumptions:

-

DNGS Construction Change Room 16 - 31718

Full Release Business Case Summary D-BCS-28200-10004-R001

Attachment "A" **Project Cost Summary**

$000's Capital & OM&A	LTD Prior Yr 2008	This Release 2009	This Release 2010					Later	Total
Project Management (OPG)	863	910	234						**2,007**
Engineering & Drafting (OPG)	304	227	136						**667**
Material	300	1,385	-						**1,685**
Installation – PWU, BTU	1,401	660	-						**2,061**
Contract - Design	2,072	380	25						**2,477**
Contract - Installation	8,134	2,663	-						**10,797**
Contract - Other	104	-	-						**104**
Security	100	-	-						**100**
									-
Interest (Capital Project Only)	245	300	-						**545**
Project Costs (excl contingency)	**13,523**	**6,525**	**395**	**-**	**-**	**-**	**-**	**-**	**20,443**
General Contingency		979	59	-	-	-	-		**1,038**
Specific Contingency		1,500	800						**2,300**
Project Costs (incl contingency)	**13,523**	**9,004**	**1,254**	**-**	**-**	**-**	**-**	**-**	**23,781**
2009-2013 Business Plan	9,316	2,613	-						**11,929**
Variance to Business Plan	**4,207**	**3,912**	**395**	**-**	**-**	**-**	**-**	**-**	**8,514**
Committed Cost									**-**
Inventory Write Off Required									**-**
Spare Parts / Inventory									**-**
Total Release (excl contingency)	**13,523**	**6,525**	**395**	**-**	**-**	**-**	**-**	**-**	**20,443**
Total Release (incl contingency)	**13,523**	**9,004**	**1,254**	**-**	**-**	**-**	**-**	**-**	**23,781**

Ongoing OM&A (non-project)									**-**
Removal Costs (incl in above)	**125**	**700**	**190**						**1,015**

Basis of Estimate					
Design Complete	100%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	N/A
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	Yes
Similar Projects	No	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2008-2012 Business Plan will be addressed through the portfolio management process. A PCRAF is not required .

Reviewed By:

Dec 11/08

Stephanie Tham
Project Manager

Date:

Approved By:

Dianne Gaine Dec. 12/08

Dianne Gaine
Eng & Mods Manager (Strat IV)

Date:

DNGS Construction Change Room 16 - 31718

Full Release Business Case Summary D-BCS-28200-10004-R000

Attachment "B" **Project Variance Analysis**

Capital	LTD Dec 2008	Total Project: Last BCS Feb 2008	Total Project: This BCS Dec 2008	Variance	Comments
Project Management (OPG)	863	**1,125**	**2,007**	882	multiple parallel activities & 2010 costs
Engineering & Drafting (OPG)	304	**335**	**667**	332	scope change and field changes
Material	300	**660**	**1,685**	1025	electrical equip, whole body monitors
Installation – PWU, BTU	1,401	**519**	**2,061**	1542	field changes
Contract - Design	2,072	**1,168**	**2,477**	1309	scope changes & field changes
Contract - Installation	8,134	**8,100**	**10,797**	2697	scope changes (completed design)
Contract - Other	104	**69**	**104**	35	
Security	100	**24**	**100**	76	
				0	
Interest (Capital Project Only)	245	**440**	**545**	105	
Project Costs (excl contingency)	**13523**	**12440**	**20443**	**8003**	
General Contingency		**3732**	**1038**	**-2694**	
Specific Contingency			2300	2300	temporary power & smoke exhaust
Project Costs (incl contingency)	**13523**	**16172**	**23781**	**7609**	
Committed Cost			0	0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**13523**	**16172**	**23781**	**7609**	
Total Release (excl contingency)	**13523**	**12440**	**20443**	**8003**	

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)		**816**	**1015**	**199**	

Comments:
Details of Project Cost Increase

- The Project Management, Contract Management Office, Field Engineering costs have all increased due the project having to complete multiple parallel activities in order to meet the tight timeline of the project in order for the CCR to be in service by March 2009 for the VBO.
- The original BCS estimate was based on only partial design completion and as identified in the risks there was a potential for design, installation and material cost increases due to the potential for scope additions. The following scope additions have contributed to the overall project estimate increase:
    - Meet newly implemented CSA N293-07 Fire Protection code :
        - Installation of double layers of fire rated drywall inside the CCR
        - Installation of concrete board on the underside and skirting of the CCR
        - Requirement to migrate the Fire Alarm signal from the Main Security Building to the Main Control Room
    - Requirement to use a 4kV power supply from the station resulted in the project having to install a 200kVA transformer, switch gear, revenue metering & transfer switch and run a 15kV line from the CCR into the station.
    - The Construction Contractor's original construction estimate was based on a partially completed design. Now that the design has been completed the contractor has provided a change notice based on changes to the design.

- The contractor was required to work overtime to maintain the installation schedule due to inclement weather and several discovery issues during excavation for the foundation and underground services
- Design Agent costs have increased due to the scope change to the electrical power supply and an increase in Time & Material costs to cover the cost of Field Changes due to discovery issues in the field during installation.
- Adjustment of the budgetary estimate for the demolition of the old CCR.
- Specific contingency of $1,500k is identified if the installation of the electrical power to the CCR is delayed and the project must provide generators for temporary power for the CCR. It is estimated that the temporary power would be required for 5 months at a cost of $300k/month
- Specific contingency of $800k for the design and installation of a smoke exhaust system if deemed required by the CNSC

The Project has implemented the following mitigating actions to contain costs:

- CNSC concurrence sought for combustible structure to eliminate the requirement to install sprinklers.
- Obtained station concurrence to build the CCR to commercial standards to reduce design and construction costs.
- Pre-fabrication of the modular units completed offsite for cost and production efficiency.
- The Project, Design & Field Engineering implemented a simplified field change process to reduce potential delays in the field.

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
15	Mar	2009	Full Release BCS
23	Mar	2009	Partial AFS (New CCR)
12	May	2009	Workplans for Demolition of old CCR Assessed
4	June	2009	Major contract awarded - Demolition
30	Jun	2010	Final AFS (New CCR)
31	Dec	2010	Project Close-out

A Project Execution Plan (PEP) will be approved by March 2009

Comments:

DND: Chiller Replacement to Reduce CFC Emissions 16 - 33631

Full Release (Phase 1) Business Case Summary D-BCS-73910-10002-R002

1/ RECOMMENDATION:

Approval of this Phase 1 Full Release is requested, to:

- Reduce the total project cost from previously-estimated 23.245M$ to 14.9M$ (Capital).
- Increase the approved amount from 6.369M$ to 10.44M$ for this Phase 1
- Purchase 11 chillers all at once instead of individually, thereby achieving significant price savings
- Install three chillers under this phase and the remaining eight in Phase 2.
- Complete the detailed engineering and procure the materials for the additional scope to improve the chiller system performance

The business objective of this project is:

- To replace the 11 existing chlorofluorocarbon (CFC) based water-cooled chillers at Darlington with units that use an approved refrigerant by January 1, 2015 in order to comply with Environment Canada's 2003 Halocarbon Regulations.
- To improve the performance of Darlington chiller systems at low load conditions.

A partial release of $6.4M was approved in May, 2006 to complete the detailed engineering, procure 2 chillers and install the T-pipe tie-ins. The detailed engineering is scheduled to be completed by Q4 2007.

During the detailed engineering, it was realized that significant savings in design/engineering costs could be realised and the costly installation strategy was not necessary if the manufacturer were to supply the chillers with the same power voltages and nozzle orientations as the present ones, i.e. custom-make the chillers to fit OPG's specific needs. The preferred manufacturer agreed to this, while also offering a significant discount if all 11 chillers are procured at the same time.

In addition, a close examination was made of certification/registration requirements. It was found that the requirements originally proposed are not necessary and thus additional savings were realized. Specifically:

- CNSC Code & Classification and TSSA Registration were exempted per newly issued N-PROC-MP-0040 and 0082.
- CRN for individual component within the chiller package is not required since the Darlington chiller system is not a registered system.
- PEO stamps on vendor's drawings are not required.

As a result, it is now estimated that the project can be completed for 14.9M$ (Capital). The experience gained during the installation of first three chillers will be used to estimate the remaining work for the Phase 2 Release.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	Partial	2,889	3,480						6,369
Requested Now	Full - Phase 1		(2,075)	3,046	1,200	1,200	700		4,071
Future Funding Req'd	Full - Phase 2				1,800	1,660	1,000		4,460
Total Project Costs		2,889	1,405	3,046	3,000	2,860	1,700	-	14,900
Other Costs									-
Ongoing Costs									-
Grand Total		2,889	1,405	3,046	3,000	2,860	1,700	-	14,900

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Sustaining	Capital	(8,778)	N/A	N/A

Submitted By:

Wayne Robbins 2007-05-07

W. Robbins
Senior VP Darlington

Date:

Finance Approval:

2007-05-18

J. Beech
VP, Nuclear Finance

Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

T. Mitchell 2007-05-31

T. Mitchell
~~Executive Vice President &~~ CNO

Date:

2/ BACKGROUND & ISSUES

Regulation Requirement

Halocarbons are chemical substances that include, among other components, halogen (bromine, chlorine and/or fluorine) and carbon. They are used specifically as refrigerants in air-conditioning and refrigeration systems, fire extinguishing agents in fire extinguishing systems and blowing agents in the manufacture of foams and as solvents. Halocarbons pose a double-edged environmental problem. Firstly, most of them contribute to the depletion of the stratospheric ozone layer. Secondly, they are greenhouse gases which contribute to climate change. Hydrocarbons are identified by an alphanumeric code, with R-11 being the most common refrigerant in use.

Environment Canada's 2003 Federal Halocarbon Regulations mandate the phase-out of equipment containing CFCs. The following specific excerpts of the regulations apply:

- "Effective January 1, 2015 no person shall operate or permit the operation of any chiller [containing CFCs]" (Section 20)
- Between January 1, 2005 and December 31, 2009 an overhauled/recharged chiller is allowed to operate for one year from the date of charging. An overhaul does not constitute the replacement of parts in the course of OPG's normal maintenance.
- The one-year grace period for repairs disappears on January 1, 2010.

The Ontario Government is seeking to phase-out CFC refrigerant on January 1, 2012, 3 years earlier than Federal Regulation. This change impacts the TRF chiller which is under Ontario Provincial jurisdiction.

In addition, the poor performance of the existing 3-way control valve is identified as impacting the chiller operating at the low load condition. Darlington requested to replace the 3-way valve and its controller in order to improve the performance of chiller system.

Project Scope

Darlington has total twelve (12) chillers inside operating island. One of TRF chillers was replaced with a chiller using R-134a as refrigerant in 2002 through Project # 31531. This project will replace Darlington's eleven (11) R-11 refrigerant water-cooled chillers with R-134a refrigerant water-cooled chillers:

- 2 chillers (2x100% configuration) in Central Service Area (CSA) provide cooling to CSA and Main Control Room (MCR). CSA chiller is in-service year-around and has no off-season.
- 8 chillers (2x100% configuration) in Reactor Auxiliary Building (RAB) provide cooling to RAB and the instruments for shutdown system. RAB chiller is off-service from November to April.
- 1 chiller (2x100% configuration) in Tritium Removal Facility (TRF) provides cooling to Heavy Water Management Building (HWMB). TRF chiller is off-service from November to April.
- Eleven (11) 3-way control valves and controllers for each of new chillers.

A revised Project Execution Plan is projected to be approved in Aug. 2007.

The chiller installation includes the removal of the existing chillers, at a total value of $330K. There is no significant salvage value to be realized from the existing/old chillers due to the age of the equipment and the phase-out of R-11 refrigerant.

Technical/Design Requirements

The eleven chillers and other required materials were originally estimated to cost [redacted] however the lowest acceptable bid came in at [redacted] As a result of challenging the technical/design requirements, the following changes have significantly reduced the cost of 11 chillers down to [redacted]

- Canadian Registration Number (CRN) for each individual Pressure Boundary (PB) component in the chiller package is not required per CSA B51 (PB Code) since Darlington chiller system is not a registered system. However, the vendor shall supply Darlington the chiller with one CRN per CSA B52. (Refrigeration Code)
- The requirement for vendor's drawings to be PEO stamped was eliminated from the Technical Specifications as per N-LIST-01300-10000.
- Due to the changes above, OPG is able to look for a proposal directly from the chiller manufacturer, instead of seeking the proposal through a commercial grade dedicator.

Optimized Installation Strategy

We optimized the new installation strategy as per the following changes, resulting in a reduction in the estimated installation cost from [redacted] to [redacted]

- Based on a Constructability Operability Maintainability and Safety (COMS) screening conducted at the scoping phase in 2004, we had planned a costly strategy to install T-pipe tie-ins and "3rd chiller" (to provide backup during the installation) for the replacement of the 2 CSA chillers. Now, based on keeping the chiller physical configuration the same, thereby reducing installation duration and risks, we are able to replace the 2 CSA chillers without having to use a backup. The stakeholders agreed to proceed with this new installation strategy by re-assessing the COMS requirements.
- We requested the vendor to supply the chillers with the same power voltages and similar nozzle orientations, which will minimize the field work.

As a result of this installation strategy change, we are able to lower the estimated engineering cost from [redacted] to [redacted] and project management cost from $1.4M to $1.1M respectively due to:

- The detailed design schedule (design agency) being shortened by 4 months (Fixed price)
- The work load of OPG project team being significantly reduced.

Installation Schedule

We will use the chiller off-season, November to April, to replace RAB chillers. Two RAB chillers were selected as part of the scope of Phase I to gain installation/commissioning experience and confirm the installation cost. In addition, the TRF chiller will be replaced in Phase I to ensure that Darlington will comply with Ontario CFC regulation. The following is the planned chiller replacement schedule:

2008	Q1 2009	Q1 2010	Q1 2011
2 RAB chillers (Q1) 1 TRF chiller (Q4)	1 CSA chiller and 2 RAB chillers	1 CSA chiller and 2 RAB chillers	2 RAB chillers

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Choose One	Alt 1 (Recommended) Full Cost	Incremental Cost	Alt 2 Delay	Alt 3	Alt 4	Alt 5
Revenue							
Project Cost		(11,603)		(13,066)			
NPV (after tax)		(8,778)		(8,950)			
Impact on Economic Value (IEV)		(8,778)		(8,950)			
IRR%		N/A					
Discounted Payback (Yrs)		N/A					

Stop the Project - Not Recommended

We do not recommend stopping this project as OPG must demonstrate to the public that the company is environmentally responsible and complies with all Federal and Provincial Environmental Regulations.

To do nothing will force OPG to replace the existing R-11 chillers when they are broken down. As well OPG would face the environmental penalty after the regulation effective January 1, 2015 and would be forced to replace those R-11 chillers any way at much higher cost.

Alternative 1 - Replace eleven R-11 chillers and eleven 3-way control valves - Recommended

We recommend this alternative as it allows us to procure all 11 chillers and start replacing the existing R-11 chillers in order to comply with the halocarbon regulatory deadline of January 1, 2015. The strategy is to install three chillers, then learn from this release and obtain a Phase 2 release to install the remaining eight chillers. This alternative also makes an emergency replacement possible if any of the existing R-11 chillers fail prematurely since all 11 new chillers will be stored in OPG's warehouse.

Alternative 2 - Delay Project - Not Recommended

We do not recommend delaying this project. Although it's possible to delay the chiller replacement once a chiller has failed, the delay will be for a maximum of 2 years. The consequence of this alternative will be that:

- There will be no one-year grace period (refer to Glossary) after January 1, 2010. Any failed chiller must be replaced, instead of having it overhauled or recharged.
- A temporary chiller is required since the lead time is about one year to deliver a chiller. It will cost more to order one chiller and the additional costs in engineering and temporary tie-in for a temporary chiller.
- We are not able to conduct an emergency replacement of a chiller if an existing chiller needs to be overhauled/ recharged since there are no new chillers available. In this case, we have to install a temporary chiller (an off-the-shelf chiller) to meet the need of the emergency before the Darlington specified chiller is delivered and installed.

Alternative 3 – Do Less - Not Recommended

We do not recommend doing less since all eleven (11) R-11 chillers must be replaced in order to comply with Federal and Provincial Environmental Regulations.

Alternative 4 – Do More - Not Recommended

We do not recommend doing more as the scope of this release aligns with the project objective addressed in Project Charter

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

The major project deliverables for this project are as follows:

This Release:

- Procurement of all 11 chillers and 11 3-way control valves with controllers.
- Complete the detailed engineering for replacing of 3-way control valve.
- Revision of Project Execution Plan NK38-PEP-73910-10001
- Installation/commissioning of 2 RAB chillers and 1 TRF chiller
- Declaration of 2 RAB chillers and 1 TRF chiller in service
- Full Release BCS Phase 2.

Release Phase 2.

- Revision of Project Execution Plan NK38-PEP-73230-10001
- Installation/commissioning 11 3-way control valves
- Installation/commissioning of the remaining 2 CSA chillers and 6 RAB chillers.
- Declaration of the remaining 2 CSA chillers and 6 RAB chillers Available for Service
- Declaration of 11 3-way control valves Available for Service
- Post Implementation activities
- Project close-out

5/ QUALITATIVE FACTORS

- The addition of refrigerant leak detection and an alarm system will provide an automated early warning system. These additions have a positive benefit to worker and environment health and safety and also on equipment health monitoring.
- Improvement of equipment reliability due to new technology with commensurate reduction in ongoing maintenance and spare parts.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Since the detailed engineering has not been completed to date, the detailed installation scope has not been finalized.	The cost estimate in Project Cost Summary needs to be adjusted.	Medium	1) The cost will be adjusted at Phase 2 BCS as per actual Phase I installation cost. 2) [redacted] general contingency is available.	Low
The vendor drawings are not available.	1) The design agency may claim delay charges due to a lack of vendor's information. 2) The milestone of issuing DCP packages may be missed.	Medium	1) Actively support Supply Chain to get the the chiller PO issued ASAP. 2) Intend to introduce incentive or penalty into the PO to encourage the vendor submit the drawing as early as possible. 3) Reserve [redacted] specific contingency for delay charges.	Low
Scope				
The poor performance of the existing 3-way control valve/controller has been identified as a contributing factor to poor chiller performance at low load, however, replacement alone may not be sufficient to allow reliable operation at low load.	Additional modifications may be required impacting both cost and schedule.	Medium	1) Detailed investigation into the low load performance issues will be conducted. The most cost effective solution will be adapted. 2) Reserve [redacted] specific contingency for the additional engineering.	Medium
See Cost and Technical				
Schedule				
Very tight installation window.	The installation will be delayed one year if the off-season is missed.	Low	Expedite completion of RAB chiller DCP.	Low
Long lead time required for chiller delivery, which impacts	The off-season will be missed if the chillers are not delivered.	Low	Expedite delivery of 2 RAB chillers to meet installation schedule.	Low

on first installation.				
The new TRF chiller (RFU1, replaced in 2002) currently has difficulty running at low load condition.	The chiller to be replaced (RFU2) may not be allowed to shut down for replacement as per the scheduled period, Q4 2008.	Medium	1) Test run RFU1 in Q4 2007 to verify the low load ability. 2) If RFU1 can't meet the low load requirement, the replacement will re-schedule during next TRF outage, Q1 2009.	Low
Resources				
Availability of the installation team and commissioning team	The installation/commissioning will not happen if resources are not available.	Low	1) Work with Contract Management Office to select an installation team in order to commit to the installation labour. 2) Schedule the commissioning tasks in IPG to reserve the Mechanical Maintainer resource. (Commissioning team)	Low
Technical				
Low Load Operation Project team has identified that the capacity of the existing chillers is about 40% higher than that required during normal operation. However, the stakeholders would like to keep capacity of the new chillers the same as the existing one in case of any emergency event.	When the chiller is operated at very low load (<10%), some components, such as 3-way control valves, controllers etc. in the chiller system may be operated beyond the design margin leading to chiller trips. .	Medium	See scope risk	Low
Chiller Performance	The new chiller may not achieve the capacity specified.	Low	1) Project team will witness the tests to ensure that the new chillers achieve the capacity 0% ~ 100% (RAB & TRF chillers) and 10% ~ 100% (CSA chiller) specified by the manufacturer. 2) The manufacturer will provide a performance test report for each individual chiller.	Low
Operator and Maintainer training	The commissioning may be delayed if Operator and Maintainer are not familiar with the new chillers	Medium	1) Project Team has reserved 40 hours of basic training, provided by the manufacturer, in order for the Operators to initially startup a	Low

			chiller and the Maintainers to conduct basic maintenance before the first chiller is commissioned. Additional training will be provided as required. 2) The manufacturer will provide a service engineer to supervise the initial settings and commissioning for each chiller.	
Regulatory				
CRN is required as per refrigeration code CSA B52. (Refrigerant loop)	The chiller cannot be operated without a valid CRN.	**Low**	1) Vendor is required to supply the chiller with a valid CRN. 2) The preferred vendor [redacted] has the experience to apply CRN for its customers.	**Low**
Environmental				
Refrigerant leakage	The chemical impacts the environment.	**Low**	A refrigerant leakage detection and alarm system is provided for each chiller.	**Low**
Health & Safety				
Workplace injury or serious MRPH event.	The event may impact project schedule and costs.	**Low**	Work to be performed per existing OPG safety rules, procedures and OH&SA regulations. Any non-standard conditions will be identified via workplans and pre-job briefings.	**Low**
Large amount refrigerant leakage that may pose an increased risk to station staff.	Potentially create a chemical hazard to the staff who are working in the mechanical room.	**Low**	The refrigerant leakage detection and alarm system is interlocked with the mechanical room ventilation fan system. The ventilation fan system will automatically activate to reduce the refrigerant concentration when the refrigerant leakage reaches the set point.	**Low**
Investment				
No risk is identified.				

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	May 2011	Dec 2011	Manager Performance Engineering

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Environment Canada's 2003 Halocarbon Regulations	Will not be in compliance with the regulations after 2014.	Comply with the regulations	The new chillers with approved refrigerant in service	All AFS signatories sign-off "Declaration of Available for Service" N-FORM-10091.
2.					
3.					
4.					
5.					

Appendix "A" **Glossary** (acronyms, codes, technical terms)

- CFC – Chlorofluorocarbon
- CRN – Canadian Registration Number
- PEO – Professional Engineer of Ontario
- CSA – Canadian Standard Association
- PB – Pressure Boundary
- CSA – Central Service Area
- RAB – Reactor Auxiliary Building
- TRF – Tritium Removal Facility
- COMS – Constructability Operability Maintainability and Safety
- PB code (CSA B51) – Governing requirement for Pressure Boundary system
- Refrigeration Code (CSA B52) – Governing requirement for refrigeration system
- Evaporator – Heat exchanger, in which refrigerant cools down chilled water
- Condenser – Heat exchanger, in which refrigerant is cooled by water or air
- Water-cooled chiller – Refrigerant is cooled by water
- Refrigerant loop – A closed refrigerant loop inside chiller, including compressor, refrigerant sides of evaporator and condenser, etc.
- Chiller Package –Chiller mechanical package, including refrigerant loop, evaporator and of condenser, etc.
- R-11 – CFC based refrigerant
- R-134a – Approved non-ozone depleting refrigerant without phase-out time
- Federal Halocarbon Regulation – Phase-out CFC based refrigerant equipment on January 1, 2015.
- One-year grace period – Overhauled/recharged chiller can only be allowed to operate for one year from date of charging effective from January 1, 2005 to December 31, 2009.
- T-pipe tie-in – A new system will tie-in to the existing system through a T-pipe.
- "3rd chiller" configuration –Due to project scoping phase and conservative approach, an installation strategy was proposed to
  - Install T-pipe tie-ins first.
  - Install a new chiller (3rd chiller) at new location with new piping system, new power/instrument cables, new monorail, new plinth etc. before replacing the 2 existing CSA chillers.
  - Replace one of the existing CSA chillers with a new one.
  - Dismantle another existing CSA chiller and associated piping, cabling etc.

Appendix "B" **Project Funding History**

$ 000's Release Type	Month	Year	Previous Releases (incl contingency) Cumulative Values 2004	2005	2006	2007	2008	2009	2010	Later	Total
Developmental	April	2004	520								520
Interim	Feb.	2005		620							620
Interim	Jan.	2006			300						300
Partial	May	2006	500	576	3,367	1,926					6,369
Choose											0
Choose											0
Choose											0
Choose											0
LTD Spent	Dec	2006	501	576	1,812						2,889

Comments:

The development funding was approved for Project # 16-38433. Project number changed because the funding changed from OM&A to Capital.

Appendix "C" **Financial Model – Assumptions**

Project Cost Assumptions:

- The additional scope is added to this project as per request of project sponsor.
- The detailed engineering for the chiller replacement packages has been completed at about 80% and the cost for Design Agency is fixed.
- The additional scope will be initiated from the problem identification process.
- The chillers proposed by the manufacturer meet the technical requirements.
- OPG has received the quotation for the chillers.
- Project has a budgetary quotation for the installation cost. The installation cost will be adjusted at Full BCS Phase II as per the actual installation cost.

Financial Assumptions:

- NPV discount rate = 7%

Project / Station End of Life Assumptions:

- Station end of life at 2018

Energy Price / Production Assumptions

N/A

Operating Cost Assumptions

- The new chillers have the same operability as the existing ones. Operating costs for the new chillers will be the same as the existing ones or slightly lower.

Other Assumptions:

- For Alternative 2, a 2-year delay: it is assumed that a failure would occur, necessitating purchase and installation of a temporary chiller at a cost of [redacted]

DND: Chiller Replacement to Reduce CFC Emissions 16 - 33631

Full Release (Phase 1) Business Case Summary D-BCS-73910-10002-R002

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2006	This Release 2007	This Release 2008	Future Release 2009	Future Release 2010	Future Release 2011		Later	Total
Project Management (OPG)	450	153	157	120	120	110			1,110
Engineering & Drafting (OPG)	487	176	80	65	65	70			943
Material	[redacted]								
Installation - PWU, BTU	[redacted]								
Contract - Design	[redacted]								
Contract - Installation	[redacted]								
Contract - Other	[redacted]								
	[redacted]								
	[redacted]								
Interest (Capital Project Only)	[redacted]								
Project Costs (excl contingency)	[redacted]								
General Contingency	[redacted]								
Specific Contingency	[redacted]								
Project Costs (incl contingency)	2,889	1,405	3,046	3,000	2,860	1,700	-	-	14,900
2007-2011 Business Plan		583	4,500	4,000	3,850	4,019			16,952
Variance to Business Plan	2,889	522	(1,904)	(1,400)	(1,290)	(2,469)	-	-	(3,652)
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	2,889	1,105	2,596	2,800	2,580	1,550	-	-	13,300
Total Release (incl contingency)	2,889	1,405	3,046	3,000	2,860	1,700	-	-	14,900
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)			90	90	90	60			330

Basis of Estimate

Design Complete	Up to - 40%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	No	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by May 2007

Reviewed By:

M. Guy
Project Manager

Date: APR 26 2007

Approved By:

T. Chong
Eng & Mods Manager (Strat IV)

Date: 26 Apr 2007

DND: Chiller Replacement to Reduce CFC Emissions 16 - 33631

Full Release (Phase 1) Business Case Summary D-BCS-73910-10002-R002

Attachment "B" **Project Variance Analysis**

Capital	LTD Dec 2006	Choose One		Variance	Comments
		Last BCS May 2006	This BCS Apr 2007		
Project Management (OPG)	450	1,395	1,110	-285	Less work load due to the change of installation strategy
Engineering & Drafting (OPG)	487	1,794	1,143	-651	Less work load due to the change of installation strategy
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	2,889	23,245	14,900	-8,345	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	2,889	23,245	14,900	-8,345	
Total Release (excl contingency)	2,888	19,601	13,300	-6,301	
Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)		0	330	330	Removal costs: $30K/chiller

Comments:

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
29	06	2007	LLA - Long Lead Time Material Contracts Awarded
15	10	2007	DCP - Issue DCP package for RAB chillers, detailed engineering completed.
07	11	2007	DCP - Issue DCP package for TRF chillers, detailed engineering completed.
07	12	2007	DCP - Issue DCP package for CSA chiller, detailed engineering completed.
30	11	2007	ICA - Award Installation labour (2 RAB & 1 TRF) contract
14	12	2007	PTA - Ready for installation, work package assessed and ITP issued - U1-RFU1
11	01	2008	PTA - Ready for installation, work package assessed and ITP issued - U2-RFU1
04	02	2008	SOI - Start of Installation of U1-RFU1 chiller
10	03	2008	SOI - Start of Installation of U2-RFU1 chiller
30	03	2008	DES -- Preliminary Engineering for 3-way valve completed
20	06	2008	AFS - Declaration AFS for U1-RFU1 chiller
20	06	2008	AFS - Declaration AFS for U2-RFU1 chiller
31	10	2008	FR2 - Full Release BCS Phase II Approved
03	11	2008	SOI - Start installation of TRF chiller
23	12	2008	DCP -- Detailed enginnering for 3-way valve completed.
26	06	2009	AFS - Declaration AFS for TRF chiller

A Project Execution Plan (PEP) will be approved by Aug 2007

Comments:

FH Computer Replacement 16 - 33815

Full Release Business Case Summary D-BCS-69740-10002-R000

1/ RECOMMENDATION:

We recommend the approval of a release of $12,470K (including contingency) to perform detailed engineering and installation of replacement equipment for Fuel Handling (FH) Control Computers and their peripheral devices. This project is an essential part of the Life Cycle Management Plan. The Business Objective of this release is to ensure that the Darlington FH computer systems operate reliably by relieving them of urgent age-related reliability problems. This release is needed in order to protect station generating capacity from an inability to fuel the 4 Darlington Nuclear Generating Station (DNGS) reactors due to failures in FH Control Computer system.

Computer internals and peripheral equipment replacements must be provided quickly to prevent loss of reactor re-fuelling capacity. Control console teleprinters are failing and must be replaced within the next 24 months. The stock of spares is expected to be exhausted by 2009.

This release will provide for the design of replacement FH CPUs and their offline testing facilities. An FH system simulation testing facility will be created to prove the replacement computers and their adjusted FH Control Computer software prior to their subsequent installations. A facility that will be a source of system control components that are known to be good will be set up to support regular effective maintenance subsequent to the computer replacements.

This release will provide for FH software updates to address legacy Human Factors Engineering issues, and provide necessary data access and display for today's FH operating environment. The FH operators' console will be modified to comply with Human Factors Engineering requirements that will support safe and reliable FH System operation.

This release will provide for the design of replacements for the control console teleprinters, operators' keyboards, main disk drives and interface boards, video display generators, main FH Control Computer internal interconnection busses, changes to the Human-System Interface, and computer surveillance and maintenance terminals. The paper plant will also be brought up to date.

The installation of this equipment will take place starting in 2008 through 2012.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	Developmental	1,422							1,422
Requested Now	Partial	(643)	1,450	3,593	2,339	1,919	1,865	525	11,048
Future Funding Req'd	Full					-	-		-
Total Project Costs		779	1,450	3,593	2,339	1,919	1,865	525	12,470
Other Costs									-
Ongoing Costs									-
Grand Total		779	1,450	3,593	2,339	1,919	1,865	525	12,470
Investment Type		Class		(IEV) Impact on Ec Value		IRR		Discounted Payback	
Sustaining		Capital		5,051,449		335.1%		3.3	

Submitted By:

W. Robbins — Date: 2007-06-27
Site VP Darlington Nuclear

Finance Approval:

D. Power — Date: Aug 1/07
~~Director, Investment and Business Planning~~
VICE PRESIDENT
Corporate Investment Planning

Line Approval (Per OAR Element 1.1 Project in Budget):

T. Mitchell — Date: 7 Aug 2007
Chief Nuclear Officer.

2/ BACKGROUND & ISSUES

This project received its first funding in September 2005. The project has carried out developmental engineering in order to determine the best alternatives for resolving the age-related problems of the FH control computer system. The campaign also examined the candidate solutions for their value in view of a possible a life-extension of the Darlington plant.

As well, the main Fuel Handling (FH) video interface monitor screens in the Main Control Room were successfully replaced during this first part of the project.

This project supports initiative number 244 in the Darlington "Plant Reliability List". The Fuel Handling (FH) control computer systems are not expected to survive until the station's pressure tube end of life without the proposed device replacements. Weaknesses affect its central processing units and supporting subsystems and interfaces, including the Human-System Interface.

Reactor fuelling capacity (thus generating capacity) cannot be maintained in the long term unless action is taken to replace equipment that is now failing or about to fail. The CPUs will be out of spares by 2011. The console teleprinters must be replaced sooner, within the next 2 years.

FH Control Computer System Description

The Fuel Handling Control Computers direct the automated reactor fuelling process at the Darlington Nuclear Generating Station. Three pairs of PDP-11 computers control the trolleys, bridges and Fuelling Machine heads. Those computers are located in the Main Control Room area. An additional 4 computers control the new fuel loading into the mobile Fuelling Machine head and used fuel discharge processes in the Fuelling Facility Auxiliary Area buildings. Another PDP-11 is used for Fuelling Machine head setup and maintenance in the plant's Central Service Area.

All of these computers must be functioning reliably in order to maintain automated fuelling capability. Automatic fuelling capability is required to stock the reactors with fuel that will keep reactor power levels in a range that will ensure economical nuclear fuel burn up and prevent unit de-rating or shut down.

Two trolley fuelling systems must be available in order to maintain adequate fuelling capacity. The FH systems equipment thus have marginal redundancy. The FH systems must have high reliability from the FH control computers as it cannot afford to have reduced capacity for any extended period.

Problem Areas

Maintenance of the FH control computer systems is becoming increasingly difficult. The control computer equipment in the FH system is nearly 30 years old. A trend of increasing obsolescence of control equipment components was recognized in 2002. That trend that has continued and many critical parts can no longer be obtained, and no support from the original equipment manufacturers is available for the computers.

The most critical age-related problems in the Fuel Handling Control Computer systems are in the

- Operator's main console,
- Main computer console tele-printers,
- Disk drive sub-systems,
- Custom operator keyboards,
- Video Display Generators,
- Computer backplanes,
- Human-System Interfaces,
- Central Processors and power supplies, and
- Inadequate Component and Software Test Facilities.

Operator's Main Console

The existing Fuel Handling main panel was designed prior to now-compulsory Human Factors Engineering (HFE) reviews. The main panel layout exhibits a number of flaws because of this. One of the most serious problems is that operator must have his/her back to the main panel displays in order to enter data in another computer during times when high panel vigilance is required. Serious HFE problems were formally recorded in "Human Factors Assessment of the Control Centre Arrangement" [R-2] in 1997. This project addresses those as well as subsequently identified problems such as poor information grouping in displays, line-of-sight to outer panels, and inadequate indication of used fuel transfer status.

Main panel switches and indicators are labeled inconsistently among panels and their associated operating and design documentation. These problems are described more fully in "Fuel Handling Human Factors Issues" [R-1]. An attempt was made in 2005 by the Main Control Room Furniture project to resolve panel peripheral visibility and operator seating orientation. The work was unsuccessful in resolving these issues since the engineering resources needed to relocate main control interfaces to a new desk were not within the scope of that project.

Main Computer Console Tele-Printers

The tele-printers are old-style LA120 computer terminals that are used for direct communication with the FH Control Computers. They produce a printed record of all the FH machine control operations, errors and events. They are also used for computer start up, shut down, maintenance operations and emergency system control.

The LA120 tele-printers suffer from failing key-switches, and mechanical failures of the feed mechanisms, carriage drive and print heads. There are no more print heads available. The only source of the spare parts is from previously failed LA120's. Main circuit board electronic components are becoming increasingly unavailable as well.

Disk Drives and Sub-System Controllers

Non-repairable and Insufficient Spares

The disk drive controller used on FH computers is obsolete, unsupported by any manufacturer, and not repairable. When the boards were purchased, a less than optimal number of spares were obtained. The controllers use a protocol that will soon be obsolete. There appear to be 2 options to prevent this weakness from shortening the computer's' life expectancy. The disk controllers could be replaced so that they work with an easily replaceable type of disk drive. Alternatively, long-life drives that are compatible with the existing controllers could be put in place.

Custom Operator Keyboards

The automatic input and semi-automatic control keyboards are subject to failures related to key-switches, memory chip failures and various electronic component failures. The power supplies of the semi-automatic keyboard are out of spares. The power supplies are increasingly difficult to repair due to their physical design and difficulties with obtaining replacement electronic components. The last of the failed keyboards are being cannibalized for replacement keys.

Display Generators

Each of the 6 Main Control Room FH computers is connected to a Ramtek model RM9400 video Display Generator (DG). The DG is required all the time when a fuel handling system is transferring nuclear fuel. If a DG becomes unavailable, an entire fuelling system is unavailable for service. Interruptions in operation of the video generator leave the operator without automatic fuelling control and without access to the system status data provided via the FH computers. Fuelling runs have to be suspended until a DG repair can be performed.

Instances of degraded performance of these units have coincided with slow operation of the control computers, resulting in stalls during the high-risk transfer of irradiated fuel from the F/M heads.

Computer Backplanes

The FH computer boards are plugged into a common back-plane via board-edge connector sockets. This backplane is prone to non-repairable failures with age. Each back-plane contains from 54 to 264 sockets. Each socket has dozens of individual connections that are made by an unsoldered compression wire wrap using very fine gauge wire. When one of these connections fail, it is extremely difficult to localize. This is made more difficult on FH computers, since they lack a connection for a logic analyzer like the one added to the DCC computers by OPG.

Human-System Interface

The FH Control Computer software contains numerous long-standing deficiencies in video display data presentation. For instance, there are identical displays for similar equipment that is located in different buildings at the station. The building is selected when the display is active. If the display is exited to check on other status, the selection of equipment will change and the drive the equipment in the wrong building. These and many other problems were important enough that work was started to correct a number of these problems in 1994. That work was inadvertently abandoned due to changes related to funding and other re-organization issues when Ontario Hydro changed to OPG. The software shipment that was started needs to be finished. As well important problems that were identified in the Human Factor Engineering survey of the FH control system need to be resolved.

Central Processors (CPUs)

The FH Control Computers use model QED95 Central Processing Units. The QED95 CPUs were used to replace the original model PDP-11 CPUs when a significant processing performance was needed to reach the commissioning target for system response. The QED95s perform well but make use of a memory storage technology that is has a wear-out period that is entered about 10 years from when they are loaded with their program. The memories can't be re-written. As well, the board construction prevents replacement of those electronic components.

The number of spares CPUs that were originally purchased assumed a lower failure rate and greater ability to repair them than was seen after they were placed in service. There have been ongoing failures in the CPUs of an undetermined nature. This situation is complicated by having too few spares to get to the station end-of-life. We expect that the stock of spare QED95 CPU's will be exhausted by 2012 based on the observed failure rates.

CPU Power supplies

These power supplies are not expected to last for the life of the station and are at best only marginally adequate for their present use.

There have been ongoing refurbishments of the power supplies. The power supply reliability can't be ensured since many electronic components required by this refurbishment campaign are expected to become completely unavailable in the next few years. Some of these components are those most susceptible to aging, and thus needing replacement (for example, electrolytic capacitors). These parts have limited shelf lives as well and so a strategy of increasing inventory to maintain parts availability wouldn't help since the parts could fail in storage before they were needed.

The present power supplies were designed for the original PDP-11 CPU, not the present QED95 CPU. CPU lock-up during brown-outs or computer re-starts can happen, as seen during the Bulk Electrical System Failure of the Northeast grid in 2003. An uninterruptible power source is required instead of the existing switch-style supplies in order to prevent CPU lock-ups.

FH System Simulator

The problems that need to be resolved by a computer simulation of the FH system are:

- Insufficient time to fully commission the FH system control on-line
- No test facilities for proving protective logic in OpData (FH machine control programs)
- No test bed for representative integration testing of FH application software changes

Allows Off-line Commissioning of CPU Replacement

The simulation of the Fuel Handing system equipment will be developed to support the testing and commissioning of the CPU replacements in an off-line environment. This will make a retrofit of all 3 FH trolley control systems possible, while maintaining sufficient on-line fuelling capacity to support operation of the 4 Darlington reactors. For DCC computer systems, commissioning can be done during outages. This possibility does not exist for Fuel Handling systems, since they continue to operate through Unit outages. Unit outages present additional demands to FH, since the fuelling equipment redundancy is reduced when one system is dedicated full time to support reactor inspection equipment.

Although the upcoming Vacuum Building Outage (VBO) presents a time when reactor fuelling is not required, the constraints on the FH system operation make it an unsuitable to commission the processors and software. The time required to perform the commissioning work will exceed the length of the upcoming VBO. The commissioning testing will require the trolleys to traverse full length of the fuelling duct. As well, ports that cross containment boundaries would need to be opened, which is inappropriate activity for this kind of outage.

Provides a Needed Software Test Bed
The Fuel Handling system simulation will be used to verify changes to the complex fuel handling software. This will help ensure that software changes do not adversely affect the operation of the Fuel Handling Systems. A realistic off-line testing facility has not been available to verify fuel-handling software. Most of the control programs were developed during plant commissioning before reactor fuelling began. This method is obviously no longer available.

Hot Spares System
A standalone computer system is required to pretest and provide a stock of ready hot-swappable computer and control components for the fuel handling systems. This facility is available for computer systems of similar complexity, such as the common process and reactor controller DCCs. The absence of the Hot Spares system has resulted in significant delays in returning Fuel Handling computer and peripheral equipment to service.

This facility for FH Control Computers existed at one time. However the system was disassembled and removed by the plant computer maintenance group in 2004 so that a second DCC maintenance computer could be installed in its place. The FH Hot Spares system has not been reinstated since that happened. Some components for that system are missing due to their consumption as spare components in the running systems and will need replacement.

Surveillance and Monitoring Terminals
The Field Monitor and External Protective Operator Display computers are used to perform monitoring of system conditions and updates to programs in the Auxiliary Control Equipment Computers. These IBM-PC compatibles are obsolete as is their operating software. The spares for both of these computer systems are exhausted and they can't be repaired.

<u>Related Projects</u>

Lessons learned from projects 40505 (FH Typer), 33509 (Obsolete Computer Components) and 33977 (DCC Replacement) will be used by this project. Project 40505 replaced a tele-printer on the Pickering FH control interface that was similar to the Darlington FH console tele-printer. Project 33509 has provided replacements for certain critical DCC subsystems that use the PDP-11 computer. Project 33977 has started the design and manufacture of the new CPU that will be used to replace the PDP-11 CPUs in various DCC Computer systems. This computer CPU will also be used to replace the FH Control Computer's QED95 CPU.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3	Alt 4	Alt 5
Revenue	(20,071,403)	(1,879,309)	(1,879,309)	(6,219,845)	(3,854,015)	(1,564,501)	
OM&A	(1,041)	-	-	-	-	-	
Capital	-	(10,337)	(9,558)	(17,033)	(24,820)	(27,870)	
NPV (after tax)	(5,883,511)	(832,841)	(832,062)	(2,665,336)	(1,697,000)	(761,474)	
Impact on Economic Value (IEV)	N/A	5,050,670	5,051,449	3,218,175	4,186,511	5,122,037	
IRR%	N/A	237.0%	335.1%	41.3%	138.8%	237.0%	
Discounted Payback (Yrs)	N/A	3.4	3.34	10.1	3.4	3.4	

Stop the Project - Not Recommended
This involves rejecting the recommendation and not providing the requested scope. The impact would be a loss of automated reactor fuelling capacity by 2011. Experience with the Darlington Fuel Handling (FH) control system in 2006 supports the assumptions of failure rates stated in the first BCS for this project. Substantial parts of the FH control computer system must be replaced before 2010 to support continued safe fuelling of Darlington's reactors. The FH System weaknesses with their probability of contributing to unit de-rating and shutdown are:

1. Console teleprinters P = 1 in 2010
2. Disk drive sub-system P = 1 in 2010
3. Display generators P = 1 in 2011
4. Operator keyboards P = 1 in 2012
5. Central Processor (CPU) P = 1 in 2013
6. Computer backplanes P = 1 in 2014
7. Operator's console P = 0.8 by 2020
8. Human-system interface P = 0.7 by 2020
9. Test Facility P = 0.7 by 2020

Attachment D shows graphs of reactor fuelling loss probability in both cases of stopping the project and proceeding with alternative #1.The failure of a Fuel Handling system to run is expected to reduce the number of reactors that can be fuelled from 4 to 2. Due to redundancy requirements, mechanical failures due to aging and so forth, 3 units are not supportable with 2 fuelling systems. The second failure will reduce the serviced reactors to 1. A planned station out of service date of July 2050 is assumed for the cost of lost generation.

Alternative 1 - Replace Main CPUS and Peripherals by Emulators - Recommended
The computer's central processor (CPU) would be replaced by a processing unit which is based on a hardware emulation of the originally installed PDP-11/70 computer. It would execute all the software now used to fuel the reactors.

Largest Savings in Software
This alternative allows the automated fuelling system to continue operation using the existing custom FH application software. This ability is important, since the existing Fuel Handling software was written in a language that will not permit it to run on any other family of computers. The system specific language was used in order to speed the operation of the computer programs and to support the large number of complex functions operating on the same computer.

The retention of the same software represents an estimated savings of about 6 million dollars, in addition to avoiding the operational and other risks inherent in developing new software code.

...s alternative will result in minimal impact to existing software programs and guarantees greater compatibility ...n the existing FH systems than a software emulation approach. This alternative has already proven to be cost effective in an installation of an earlier vintage of hardware emulator, in the Darlington FH systems.

Available Technology

The CPU emulator, the QED970, is based on an enhanced design of an existing product, the QED95. The same company that is providing DCC life extension support for the CANDU 600 control computers will be used to acquire the QED970 emulators.

Renovate the Peripheral Equipment

The use of the QED970 CPU will provide a platform for the upgrading or replacement of the video display generators, consoles, control keyboards and printing terminals, all of which have exhibited significant design and/or maintainability issues

Alternative 2 - Delay Project - Not Recommended

Past delays to the start of this project have removed all substantial float time between computer system replacement component design, and installation and the ability to fuel the reactors without substantial disruption. Experience with the Darlington Fuel Handling control system in 2006 supports the assumptions of failure rates stated in the first Business Case Summary for this project. The successful replacement of the main control panel video screens barely kept ahead of the obsolete video unit failures. At one point, a Fuel Handling equipment delay caused rescheduling of installations. This would have resulted in the loss of 1 trolley fuelling system during the fall outage. This was averted by exceptional efforts by FH Maintenance, who was installing the new monitors, by reallocating work. This near miss underscores the need to continue without delay.

Delaying the project would result in a dramatic increase in cost to extend the FH control computer life due to a missed opportunity to buy from what is expected to be the last production run of the QED970s in 2009. In the best case, there would be cost increases to provide another production run. The cost of a subsequent run would likely be higher since the market for these devices is very small, and the customers will be those with mission critical systems whose replacement cost would justify a substantial outlay for hardware. If components on these boards become obsolete before a production run could be arranged, re-engineering of the boards may be required at extra cost.

There is a risk that the QED970 design staff would not be available to do this re-engineering. In that case a separate engineering campaign would be required in order to develop another emulator for FH. Investigations by the DCC replacement project placed the cost of that work tentatively at 10 million dollars.

Alternative 3 – Replace Main CPUS and Peripherals with State-of-Art Equipment - Not Recommended

A full replacement of the PDP style control computers with new technology is not recommended for this phase of the Fuel Handling computer aging management strategy.

This would be an opportunity to have the software prepared to modern standards, which could increase the reliability, robustness and functionality of the controller's software. At that time, the redesigned software would be more easily portable, thereby reducing future costs of hardware replacement.

Would Need More Time Than Available

Although this alternative may be the best option for long term supportability, there is not enough time or internal resources to execute this alternative before the existing computer equipment fails irreparably. Replacement of the existing CPUs must be done before 2011, given the current number of spare units and failure rates. Other peripheral devices must be replaced sooner. A re-writing of the controller software, testing it with a system simulator with adequate category 3 quality assurance standards and its installation is expected to take a minimum of 4 years. The consequences of lost fuelling capability and subsequent generation loss resulting from project delays when changing to this type of control system is too great to start down this path at this time.

Best Cost Recovery Only when Entire Trolley Control Replaced

The feasibility of replacing the FH control system auxiliary (FFAA) controllers was examined in the preliminary engineering phase. The intention was to only replace the FFAA main controllers. We determined that commercially available equipment would be suitable for the control application. However another custom device would be required to allow compatible communication with the main controller. This device would not be required after the main controllers were replaced by a modern style controller. As a result, the significant investment in the custom communication adapter device would be lost. It would be better to carry out a replacement of both main and auxiliary controllers together to make best use of modern technology. As well this should be done when there is not as much concurrent work in this project. The concurrent work is needed to replace equipment before system operability is lost. Full focus should be applied to a controller "re-hosting" to new technology in order to transfer the knowledge to OPG from any outside design agencies that might be involved.

Alternative 4 – Two-Stage Repalcement of Main CPUS and Peripherals - Not Recommended

A Two-Stage Replacement of Main CPUS and peripherals is not recommended for this phase of the Fuel Handling computer aging management strategy.

In comparison with alternative 1, this alternative would entail a slightly reduced scope of changes to the FH software and teleprinters. However the CPUs would still be replaced. Subsequently, the replacement CPU equipment would be replaced with state of the art computers, or Programmable Automation Controllers (PAC).

This could increase the reliability, robustness and functionality of the controller's software. This would increase the ease of maintenance for the hardware and software if the life of the DNGS plant is extended. In comparison with alternative 3, this avoids the generation losses that would likely occur due to the time needed to re-design the control software and install a new technology system. The new CPUs that are displaced by the new PACs could be returned for stores, ensuring that the DCCs, that also use the new CPUs, would have plentiful spare parts.

Would Need Retention of Rare Knowledge
Although this alternative may be a very good option for long term supportability, and power generation support, there is no way to be certain that people skilled in Fuel Handling controls and PDP-11 computers will be available for the extended duration of the project. A re-writing of the controller software, testing it with a system simulator with adequate category 3 quality assurance standards and its installation is expected to take a minimum of 4 years longer than the Alternative 1 replacement. Due to full use of those resources in the first part of the project it would not be possible to re-use those for parallel software design, transfer the skills and knowledge to others nor effectively coordinate additional work by external design agencies.

The consequences of the failure to complete the project could be a loss of several million dollars of investment capital.

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

The modifications required by this project can be classified as directly age related or design related. The age related changes are needed to prevent loss of system function as parts degrade and become non-repairable. These changes affect the Main Control Computer, Display Generator and Tele-printers.

The design related changes address simple and time-compounded design misconceptions. These changes fix long standing problems and thus provide a sound base upon which future modifications can be made. These changes improve the Fuel Handling Human-System Interface. The Fuel Handling (FH) operators will experience improvements in reliability and function of the main control keyboards, FH controller software, the Main Control Room FH Panels, and the Operator's desk, as well as improved access to control computer data.

The modifications are outlined in more detail in the following paragraphs.

Aging Related Improvements

Main Control Computer

The Main Control Computers' central processors will be replaced in the CSA and FFAA control computers by new software compatible QED970 units.

Prior to the installation of these new units, which have a long lead time, a number of obsolete components will be removed from the FH control computers to increase system reliability. These components are potential sources of system malfunction since they are no longer required but affect the computer main bus. These components include RL02 disk drives and interfaces, video printer switches, and some high and low speed network communication adapters.

Maintenance documentation will be brought up to date with the existing configuration and kept current as changes are made.

The main disk drives and controllers will be replaced by new interfaces to the main bus and long-life sold state drive units.

The existing computer software/hardware test facility will be upgraded in order to fully test the new central processors, computer configuration and attendant software changes. It will be equipped with a computerized simulation of the FH field equipment so that performance of the new computer components can be realistically gauged and verified for used in the plant.

The original hardware maintenance facility will be re-established. Also, in support of maintenance, the life of key maintenance and supervisory computer tools will be extended. These include the External Protective Operator Display, Protective Ladder Software Test Tool and Field Monitor computers, which will be upgraded to use commercially available components and software.

When the main Central processors are replaced, the main computer cabinets will be optimized. The main power supplies will be replaced with more efficient and reliable units at that time. The main backplane segments that hold the processors and adapter boards will be replaced as well.

Display Generator Replacement

The Ramtek Model RM9400 video display generator will be replaced by a computerized device that will produce displays based on the instructions sent by the control computers. This will greatly reduce the amount of change to the control computer software.

Tele-Printers Replacement

The Model LA120 tele-printers will be replaced by IBM PC-compatible computers. They will allow operators to access the control computers in the same way as they do now. The new equipment will provide fast access to a larger amount of each system's operating history in order to support returning systems to service more quickly.

Field Monitor and EPOD Replacement
The surveillance and maintenance computers will be re-hosted in new computer hardware. The software will be updated as necessary to ensure easy maintenance.

Design-related Improvements

Automatic and Semi-Automatic Control Keyboards
The keyboards will be replaced by commercially available keyboards. Keystroke signals will be mapped by a small computer that will communicate with the main FH control computers.

FH Controller Software
The software in the main control room FH computers will be modified to correct problems related to information display. The software corrections will span approximately 4 shipments in order to shorten commissioning time and reduce the risk of unexpected interaction between concurrent modifications.

Main Control Room FH Panels
Switches and Indicators labels will be changed to eliminate confusion about the purpose of switch or state of the devices. The Labeling will be made consistent between panels and documentation.
Un-used switches and indicators will be removed from the panels. The FFAA computer re-start switch will be replaced to prevent accidental operation. The Irradiated Fuel related indicators will be upgraded to ensure that they provide information in appropriate to their function during the fuelling process.

Operator's Desk
The Video Display terminal count and position will be optimized when a new desk is put in place. The desk will place the operator so their line of sight will be towards the panel during reactor fuelling.

Improved Access to Computer Data
The tele-printers will be connected to a network so computer log and IO data is easily accessible to FH operators and technical support staff. Predefine monitoring screens will permit timely monitoring of Fuel Handling in a post transient situation. Electronic files retrieval will be simplified to eliminate computer history data loss.

5/ QUALITATIVE FACTORS

Completion of this project will result in more reliable Fuel Handling System Performance. Some key benefits are:

- Maintenance effort will be reduced
- Spare parts supply will be made adequate
- System health reports concerns will be addressed
- Forced loss rate escalation due to failures of current equipment will be avoided
- Dependence on a single supplier for support of the Fuel Handling Systems will be eliminated
- Obsolescence of peripheral equipment (e.g. LA120 terminals, Display Generators, disk drives, keyboards) will be addressed
- Operator issues associated with Input Devices will be addressed
- Risks associated with software changes will be mitigated by providing a FH Simulation facility.
- On-line fuelling of Darlington reactors can be maintained by the new FH Simulation facility which will avoid taking FH systems out of service for extended periods in order to commission new software and hardware.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Design Agency costs may be higher when contract negotations proceed	Higher costs of external support providers who do not fully understand the work scope.	**Medium**	Provide tightly defined scope to supply chain for inclusion with requests for Proposals, thus reducing liklihood of bidders underestimating effort required. Use contingency funding.	**Low**
Scope				
The Customer (FH Operations) changes expectations of the project's deliverables.	Reluctance by Operations to sign-off on AFS for equipment	**Medium**	Have FH manager sign-off on Project Plan so there is a clear understanding of the deliverables and schedule	**Low**
Schedule				
Changes to supply chain policy or staffing results in extended delays to arrangement of contracts for design and supply	Loss of coordination of project segments increases interest costs and may delay overall time to project close-out	**Medium**	Obtain Sevice level agreement signed with Supply Chain	**Low**
Delays due to failure of other FH equipment	Failure of mechanical components of FH system delays equipment installations since the focus of FH Maintenance will be shifted to re-stablishing fuelling capacity rather than installing new equipment.	**High**	Obtain agreement from FH Maintenance section manager to work with the project to blend FH work with project installations following return to service of failed equipment. This will minimize work-bumping	**Low**
Delays due to reactor closure plug replacement	The FH control systems will have less idle time in which to install replacement equipment if the all the reactor closure plugs need to be replaced (now being proposed)	**High**	Perform as much commisssioning work as possible for the replacement equipment in simulated environments. This will reduce the length of the installation and commisioning time needed in the Main Control Room.	**Low**

Resources				
Loss of internal resources with knowledge of fuel handling software	Possible schedule delays in implementation of Hot Spares system, controller display problem fixes, and FH FFAA system simulator	**Medium**	Coach and provide mentoring to other members of the DCC group so redundancy exists, shortening time to recover schedule if key member leaves	**Low**
External design agency becomes unavailable to the project due to their commitments to other customers during the design part fo the project	Possible schedule delays in implementation of Hot Spares system, controller display problem fixes, and FH CSA system simulator	**Medium**	Diversify allocation of design contracts to decrease effects	**Low**
Potential suppliers fail to bid for parts of the project	Nuclear station refurbishment and promises of new-build are increasing demand for traditional supplier's services. New-build contracts may be considered more lucrative and result in suppliers focusing on nuclear new-build instead.	**Medium**	The external work for this project can be arranged in 2007 rather than waiting to initiate contracts later. Nuclear new-build request for proposals are not likely going to be issued until after 2008.	**Low**
Technical				
Loss of primary design resource for CPU replacement (QED, Inc)	Restart of CPU hardware design process adding extra cost and delay to schedule and possible derating	**Medium**	Secondary agency (MAPPS) is providing design oversight and can carry on the design process if primary designer is lost	**Low**
Regulatory				
Change in regulator's policy may require more time consuming administrive overhead in order to put the new CPUs in service	Delay to the implementation of the processors results in delay in CPU installation schedule. Non-recoverable failure of old CPUs results in decrease fuelling capacity and unit derating	**Low**	Formal communication to Darlington Licensing Section to inform them of this risk, asking that this project be informed immediately of a change in regulator policy in this area, so we have more time to comply	**Low**
Environmental				
No risks identified.				
Health & Safety				
No risks identified.				

Investment				
No risks identified				

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Feb 2012	Jul 2013	Manager, Fuel Handling

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Central processing units function reliably	Functional failure rate of 2003	No failures in 12 months folowing installation of new CPUs	Functional failure count per SCI 69740 health report	Fuel Handling Technical, System Engineer for 69740
2.	The deficits indentified in the 2005 Human Factors analysis have been resolved.	NK38-REP-63500-10002	The elements from the report that were scoped for this project are resolved	Post implementation comparison against baseline.	OPG Human Factors Engineering group
3.	All peripherals operate reliably.	Passport work order data	Less than 2 failures per device type per year following installation of devices	Functional failure count per SCI 69740 health report	Fuel Handling Technical, System Engineer for 69740
4.	Adequate maintenance strategy is active	Maintenance department is struggling to keep equipment in service	A sufficient quantity of serviceable spares are available	Less than 4 trolley system-days per year are lost due to delays in obtaining replacement equipment	Fuel Handling Technical, System Engineer for 69740
5.	Commissioning time does not impede the ability to maintain adequate zone levels in the 4 Darlington reactors	No trolleys are unavailable due to FH control computer malfunctions during commissioning	No units shut down or de-rated due to the effects of commissioning this project's elements	Darlington outage report and Darlington SCR database	Fuel Handling Technical, System Engineer for 69740

Appendix "A" Glossary (acronyms, codes, technical terms)

CPU Central processing unit, the heart of the FH controller. It executes program instructions to control the input – output equipment and so the field devices of the FH system.

CSA Central Service Area of the Darlington Plant. This is the location for the main trolley and FM head control computers.

DCC The Digital Control Computers that control the reactors. Also used to refer to the Darlington computer design group.

FFAA Fuelling Facility Auxiliary Area. This abbreviation is used to refer to the equipment contained in either of the 2 buildings used to load, discharge and store nuclear fuel. The buildings are adjacent to the extreme east and west ends of the 4 reactor buildings.

LA120 The model number of the printing terminal used as the primary interface with the FH control computers. It works similarly to a "dumb" terminal, but communicates by printing on tractor feed paper instead of by graphic display on a video monitor.

PDP-11 The "Programmed Data Processor", originally produced by the Digital Equipment Corporation of Maynard Mass., USA in 1978. The DN FH computers were originally model PDP-11/70, the 21 bit addressing version.

RM9400 This is a model of video display generator that is used to receive computer instructions from a PDP-11 computer and turn them into video signals. The signals are sent to special monitors when the images are viewed.

QED95 This is a "work-alike" computer processing unit for the PDP-11/70. It was built in 1993 to support life extension of systems that used PDP-11/70 computers that had a large investment in software. This allows the existing computer systems to run using the same software. These are used in the FH computers.

QED970 This is a more modern "work-alike" computer processing unit for the PDP-11/70. It is being designed to replace the QED95. The new design addresses the maintenance issues with the old QED's so that they will last at least to the DN station's end of life.

References

1 NK38-REP-63500-10002 R00, "Fuel Handling Human Factors Issues", OPGI, 2005

2 NK38-REP-66000-001 R00, "Human Factors Assessment of the Control Centre Arrangement", Greenley & Associates, 1997

Appendix "B" **Project Funding History**

Choose Release Type	Month	Year	All Existing and Planned Releases (incl contingency) Cumulative Values 2005	2006	2007	2008	2009	2010	2011	Later	Total
Developmental	Sep	2,005	1,422								1,422
Full	May	2,007			11048						11,048
											0
											0
											0
											0
											0
											0
LTD Spent	Dec	2006		779							779

Comments:

The project is included in the 2006-2010 Business Plan at a value of $6.9 Million. A variance to the 2006-2010 Business Plan of $3527K will be addressed via inclusion in the 2008 Business Plan. A Project Execution Plan (PEP) is scheduled for completion by Q3 2007.

Appendix "C"

Financial Model – Assumptions

Project Cost Assumptions:
The device that will be used to replace the CPU will be the same one used for the Darlington DCC computer replacement. The development of the device will be successful and meet the schedule included in the contract with the vendor of the device.

Financial Assumptions:
Not applicable.

Project / Station End of Life Assumptions:
The Station End of Life is assumed to be extended by a refurbishment with a new end of life of April 1, 2050.

Energy Price / Production Assumptions:
$49.50 per Megawatt-hour. Nominal 900 MWe net output, 97% capacity.

Operating Cost Assumptions:
Darlington Station operating funds will be used to pay for spare computer component that are purchased by this project and are consumed during the station's life after the closure of this project.

No Additional staff will be required to run the new equipment. Training costs will be small since the new equipment will be very similar in operation to the equipment that is replaced.

Other Assumptions:
Contracts with external suppliers and design agencies can be arranged within 130 days or less.
OPG supply chain will support expeditious contract arrangements with appropriate external resources.

The project will be free to identify capable and appropriate qualified suppliers and design agents as required, subject to technical governance. OPG policy interpretations will not artificially constrain the selection of external resources in order to shorten the Approved Suppliers List.

FH Computer Replacement 16 - 33815

Full Release (Phase 1) Business Case Summary D-BCS-69740-10002-R000

Attachment "A"

Project Cost Summary

$000's Capital	LTD Prior Yr 2006	This Release 2007	This Release 2008	This Release 2009	This Release 2010	This Release 2011	This Release 2012	Later	Total
Project Management (OPG)	153	164	162	179	172	147	148		1,125
Engineering & Drafting (OPG)	299	406	482	437	381	145	148		2,298
Material	[redacted]								
Installation – PWU, BTU	[redacted]								
Contract - Design	[redacted]								
Contract - Installation	[redacted]								
Contract - Other	-	-	-	-	-	-			-
									-
									-
Interest (Capital Project Only)	[redacted]								
Project Costs (excl contingency)	[redacted]								
General Contingency	[redacted]								
Specific Contingency	[redacted]								
Project Costs (incl contingency)	779	1,450	3,593	2,339	1,919	1,865	525	-	12,470
2006-2010 Business Plan	872	1,450	2,544	900	1,129	-			6,895
Variance to Business Plan	(93)	(51)	348	983	416	1,501	423	-	3,527
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	779	1,399	2,892	1,883	1,545	1,501	423	-	10,422
Total Release (incl contingency)	779	1,450	3,593	2,339	1,919	1,865	525	-	12,470
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	Up to ~ 15%		Quality of Estimate		Conceptual + 60% to - 25%
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	No	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2008-2012 Business Plan will be addressed through the portfolio management process.
A PCRAF will be approved by Jul 2007.

Reviewed By:

E. Hung
Project Manager
June 12/07
Date:

Approved By:

R. Hohendorf
Eng & Mods Manager (Strat IV)
June 13, 2007
Date:

FH Computer Replacement 16 - 33815

Full Release (Phase 1) Business Case Summary D-BCS-99740-00002-R000

Attachment "B" **Project Variance Analysis**

Choose One	LTD Dec 2006	Choose One: Last BCS Sep 2005	Choose One: This BCS Apr 2007	Variance	Comments
Project Management (OPG)	153	483	1127	644	Close integration of multiple work segments requires more oversight
Engineering & Drafting (OPG)	299	310	2296	1986	It is more efficient to have OPG staff perform work that requires a lot on site specific information
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	**779**	**8756**	**12470**	**3714**	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**779**	**8756**	**12470**	**3714**	
Total Release (excl contingency)	**779**	**6895**	**10422**	**3527**	
Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

In order to perform the installations of replacement equipment in the manner required to prevent critical system failure, more project oversight is required. However, this is expected to provide more rapid recovery of investment, thus offsetting the higher project management costs.

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
9	JUL	2007	Video Monitor Replacement Close-out Complete
03	DEC	2008	Obsolete Equipment Removal AFS
17	DEC	2008	Main Console AFS
20	MAY	2008	Protective Display Terminal Replacement
13	NOV	2009	FH System Simulator in service
26	FEB	2010	Control Keyboard Replacement AFS
30	AUG	2010	Teleprinter Replacement AFS
22	SEP	2010	Field Monitor Replacement In Service
01	APR	2011	Computer Backplanes AFS
22	APR	2011	CPU Replacement AFS
24	NOV	2011	Display Generator AFS
28	FEB	2012	Human System Interface Software AFS
09	NOV	2012	Final Project Close-out

A Project Execution Plan (PEP) will be approved by Jun 2007

Comments:

Attachment D

Figure 1 below shows the probability of non-repairable Fuel Handling Computer System based on not proceeding with this project. There are several components that could influence this eventuality. Each is shown on a separate line. The graph in Figure 2 shows the same risk factors with probabilities of failure influenced by the actions of proceeding with alternative 1 of this project.

Figure 1 – "Stop the Project"

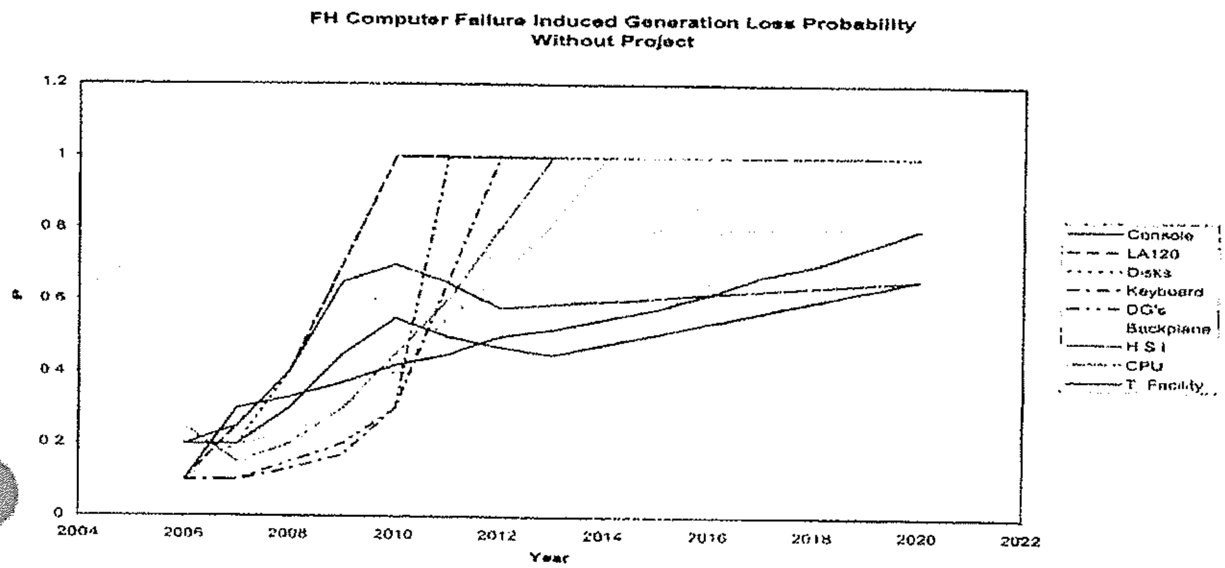
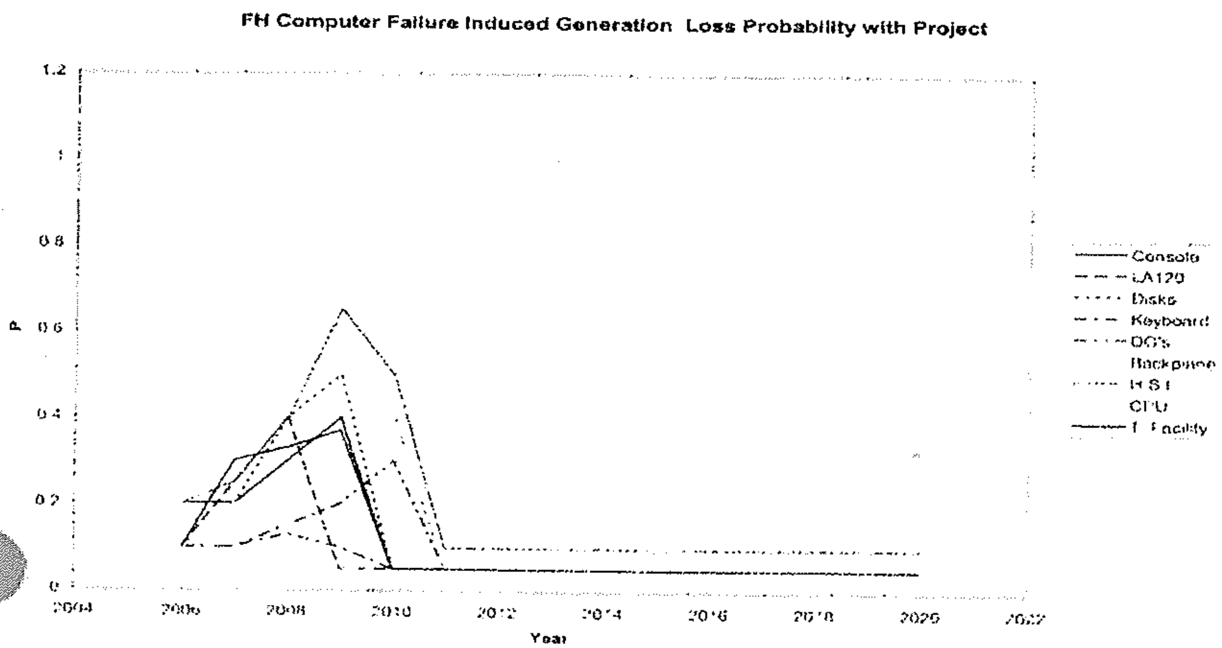


Figure 2 – "Alternative 1"



DNGS SDS Computers Aging Management 16 - 33955

Full Release Business Case Summary D - BCS - 68000 - 10002 – R001

1/ RECOMMENDATION:

We recommend a Full Release of $17.2M Capital to complete the DNGS SDS (Shutdown System) Computers Aging Management Project by the target completion date of June 2014.

The business objective of the project is to manage the current threat to generation posed by the aged status of the 57 SDS computers that are critical to station safety systems. Each reactor unit employs a network of 14 computers that is connected to one Shutdown System Monitoring Computer (SSMC), common to all four units. Due to the critical nature of the SDS computers, failure in any of the unit networks would directly result in unit unavailability.

SDS computer hardware is obsolete, spare parts inventory is low and many replacement parts are no longer available. Moreover, circuit board level repair may not be possible due to the technology employed and component and/or computer replacement is costly due to the detailed and lengthy engineering and qualification processes. Operator workarounds are currently being used to deal with system deficiencies. In its current state, it is not likely that the system can be maintained to the station end-of-life target date of 2018. Without completion of this project, we can expect significant revenue loss due to unit unavailability.

Developmental Funding ($1.8M approved in December 2006) has been used to complete Preliminary Engineering and establish the most effective and least costly replacement strategy to satisfy the business objective. This strategy involves:

- Full replacement of the SDS1 and SDS2 Monitor Computers
- Eliminate need for separate SSMC by incorporating functionality into the Replacement Monitor Computers
- Full replacement of the SDS1 and SDS2 Display/Test Computer CRT monitors with modern display units
- Engineering required to enable use of higher density memory chips on SDS2 Trip Computer EPROM boards
- Preliminary Engineering required to achieve an emulated solution for replacing the SDS2 Trip Computer DEC boards

Based on the Preliminary Engineering findings, we are also recommending the deferral of the remaining SDS computer replacement to the proposed DNGS Refurbishment Project (10-27959). This work involves the replacement of the SDS1 and SDS2 Display/Test Computers and the SDS1 and SDS2 Trip Computers and is not considered a requirement to meeting the business objective of this project, aside from the SDS2 Trip Computer engineering tasks specified above. Accordingly, the $65M cost estimate, provided in the Developmental Business Case, has been revised to $17.2M.

Note that if the work to replace the remaining computers is not included in the scope of the Refurbishment Project, a new project will be initiated at a later date for this purpose.

Currently Released	Developmental	1,783							1,783
Requested Now	Full	(549)	1,323	3,694	5,548	3,058	2,005	330	15,409
Future Funding Req'd	None								-
Total Project Costs		1,234	1,323	3,694	5,548	3,058	2,005	330	17,192
Non Project Costs									-
Grand Total		1,234	1,323	3,694	5,548	3,058	2,005	330	17,192

Investment Type	Class	NPV	IRR	Discounted Payback
Sustaining	Capital	116.1 M	143.8%	4.1

Submitted By:

Wayne Robbins 2009-06-30
W. Robbins Date:
Chief Nuclear Officer

Finance Approval:

D. Power July 13/09 Date:
V.P. Corporate Investment Planning
July 15/09

Line Approval (Per OAR Element 1.1 Project in Budget):

T. Mitchell July 16, 2009 Date
President & Chief Executive Officer

2/ BACKGROUND & ISSUES

The Darlington NGS SDS computers comprise a network of 14 computers per reactor unit connected to one Shutdown System Monitor Computer (SSMC) that is common to all four reactor units. The SDS computers are classified as part of a Special Safety System that Darlington NGS depends on to:

a) Automatically initiate a reactor shutdown via the SDS1 and SDS2 Trip computers.

b) Display SDS parameters at the main control panels (as well as the secondary control area in the case of SDS2) via the SDS1 and SDS2 Display/Test computers.

c) Provide a facility whereby the trip measurements, logic and reactivity devices can be tested from the Main Control Room via the SDS1 and SDS2 Monitor computers and the SSMC.

d) Monitor the SDS routinely to detect and notify the Operator of conditions which adversely affect production, reliability or SDS availability.

Currently, the SDS computers (totaling 57 computers for the entire station) use old technology that is increasingly difficult to maintain and for which there is no OEM support.

- The vendors of this equipment are no longer in business.
- Circuit board level repair, where possible, has been achieved through the use of existing parts; however, some critical parts are no longer available. For the SDS2 Trip Computer there is a major concern that, due to the technology employed, board level repair may not be possible.
- Failures of peripherals have caused an increased maintenance burden and spare parts for these are no longer available from the suppliers.

In addition to the hardware obsolescence issues, the SDS Monitor computers suffer from intermittent problems that are related to hardware limitations of the older technology. There have been over 70 SCRs concerning SDS computers raised in the last several years.

To address these issues, a developmental release of $1.8M was advanced in late 2006 to carry out a number of key preliminary engineering activities. This work is specified in the preliminary engineering Project Execution Plan, NK38-PEP-68000-10004 R000, and includes:

a) Determine the detailed material condition and component failure trends of the SDS1 and SDS2 Trip computers, the SDS1 and SDS2 Display/Test computers, and the SSMC.

b) Initiate the replacement of the SDS1 and SDS2 Monitor computers, and the SDS1 and SDS2 Display/Test Computer CRT monitors. The Monitor Computer replacement will incorporate the existing functionality of the SSMC and, as a result, the SSMC will be eliminated when all of the new Monitor computers have been installed. These activities include the qualification of the hardware and software for acceptability of use.

c) As an interim solution to the development of a replacement Monitor Computer, initiate the replacement of the existing Monitor Computer hard disks.

d) Evaluate the replacement of SDS2 Trip Computer components facing a critical shortage of parts.

e) Determine the replacement strategy for the SDS computers to ensure reliability is sustained at current levels or improved for the current station lifetime (2018) and ensure an upgrade path exists for plant life extension or for prior replacement, if necessary.

The preliminary engineering effort is now complete, and full release funding is being sought to carry out the remainder of the work necessary to achieve the goals of the project. (See Section 4.)

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ Millions	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2	Alt 3	Alt 4	Alt 5
Revenue	(248.8)				(86.3)		
OM&A							
Capital		(15.3)	(14.0)	(61.0)	(12.1)		
Present Value (PV)	(125.4)	(10.3)	(9.4)	(39.4)	(46.0)		
Net Present Value (NPV)	N/A	115.1	116.0	86.0	79.4		
Internal Rate of Return (IRR) %	N/A	109.0%	143.8%	56.8%	153.6%		
Discounted Payback (Yrs)	N/A	4.1	4.1	4.4	4.1		

Base Case: Not Recommended - Status Quo

We do not recommend "doing nothing" because SDS computer hardware is obsolete, spare parts inventory is low and many replacement parts are no longer available. Moreover, circuit board level repair may not be possible due to the technology employed, and component and/or computer replacement is costly due to the detailed and lengthy engineering and qualification processes. Operator workarounds are currently being used to deal with system deficiencies. In its current state, it is not likely that the system can be maintained to the station end-of-life target date of 2018. Without completion of this project, we can expect significant revenue loss due to unit unavailability.

Alt. 1: Recommended - Partial Replacement, Upgrade and Engineering Development

We recommend the strategy outlined in Section 4 because it provides the most effective and least costly way to maintain system functionality to the station end-of-life target date of 2018. Replacing the SDS1 and SDS2 Monitor Computers with modern computer systems will alleviate the critical component shortages facing the GA-based computers and remove the functional limitations and intermittent problems imposed by the current hardware platform. Completing detailed engineering to make available a sufficient supply of qualified replacement EPROMs for future software revisions will allow SDS2 Trip Computer software revisions should they become necessary. The preliminary engineering work required to achieve an emulated solution for replacing the DEC boards in the SDS2 Trip Computers will position us for detailed engineering work which would either take place as part of the DNGS Refurbishment Project or a new project to be initiated at a later date.

Alt. 2: Not Recommended - Replace the Entire Network of SDS Computers

We do not recommend this alternative for three main reasons. First, the GA-based computer critical component shortages are alleviated by replacing the Monitor Computers, as outlined in the recommended alternative. Second, the SDS2 Trip Computers are not facing such a critical component shortage threat, provided the existing maintenance strategies are maintained. Third, the effort involved in replacing the entire SDS computer network now would require more resources than could likely be obtained from both internal and external sources, especially given the safety critical nature of the SDS1 and SDS2 Trip Computers. Note that this alternative (the replacement of the remaining computers) is recommended for the plant refurbishment project (10-27959), or a new project to be initiated at a later date.

Alt. 3: Not Recommended - Only Replace the SDS1/SDS2 Monitor Computers

We do not recommend this alternative for three main reasons. First, the display quality of the existing Display/Test Computer monitors is poor and the replacements will reduce maintenance burdens and lower energy consumption. Second, the shortage of the current SDS2 Trip Computer EPROM chips is such that it would be impossible to release the next revision of the software should it be required. Third, the lead time for replacing the DEC boards in the SDS2 Trip Computers with an emulated solution will be long, so delaying the preliminary engineering would not be prudent.

4/ THE PROPOSAL

The funds requested in this full release will permit completion of the scope of work established by the preliminary engineering efforts and outlined in the Recommendation section. It consists of the following items:

1. The full replacement of the SDS1 and SDS2 Monitor Computers (MCs) with modern computer systems. This includes both the hardware and software platforms necessary to realize the solution. The baselines for the hardware and software platforms are described in NK38-REP-68000-10021 and NK38-REP-68000-10023, respectively, and have been designed to minimize the impact of future obsolescence issues. The replacement MCs will perform the same functionality as the existing ones, with the exception of minor modifications documented in NK38-MDR-68000-10002. The Computer System Requirements (CSR) for the replacement MCs will be specified in NK38-CSR-68000-10001.
2. The incorporation of the SSMC functionality into the replacement Monitor Computers resulting in its elimination when all the Monitor Computers are in service. A separate SSMC will no longer be required with the replacement Monitor Computer platforms (see Item 1, immediately above).
3. The full replacement of the SDS1 and SDS2 Display/Test Computer CRT monitors with modern display units. This includes two monitors per SDS channel in the Main Control Room (MCR) and two monitors per SDS2 channel in the Unit Secondary Control Area (USCA), plus sufficient monitors for the associated maintenance and development facilities. The cables and equipment driving the existing CRT monitors will continue to be used and so are not subject to replacement. The specification for the replacement monitors is contained in NK38-TSI-68000-10001.
4. The engineering work required for enabling the use of higher density memory chips on the EPROM boards of the SDS2 Trip Computers. This includes all the necessary detailed engineering activities required to make available a sufficient supply of qualified replacement EPROMs for future software revisions. It does not include any installation or commissioning efforts because the replacement EPROMs will not actually be required until the next Trip Computer software revision becomes necessary. Note that the supply of the existing EPROMs is so low that it would be impossible to implement any trip logic changes in the software.
5. The preliminary engineering work required to achieve an emulated solution for replacing the DEC boards in the SDS2 Trip Computers. This includes all the necessary preliminary engineering activities required to properly position ourselves for detailed engineering work which would likely take place as part of the DNGS Refurbishment Project. This approach is being investigated because a) the Trip Computer software has performed well and is worth preserving particularly since safety critical Category I software requires significant expenditures of time, money and effort; and b) the performance limitations of the current DEC hardware platform have made most anticipated future software changes impossible.

The Project Execution Plan (NK38-PEP-68000-10004 R001) will define the project scope to complete all the deliverables required to meet the milestones included in Attachment "C".

5/ QUALITATIVE FACTORS

The qualitative benefits that would be realized from implementing the recommended alternative are as follows:

- System Health Reports concerns will be addressed
- Spare parts and obsolescence issues will be addressed
- Reduced impact of future system obsolescence; improved positioning of SDS computers for future upgrades
- Improved SDS reliability up to the start of station refurbishment and beyond
- Reduced regulatory risk by replacing the most at risk computers (MCs) in the system and planning for the remainder
- Increased confidence in the software installed in the replaced computers (MCs)
- Reduced risks associated with maintaining the software installed in the replaced computers (MCs)
- Increased availability of information important to operations staff
- Improved system diagnostic capability for the system engineers
- Reduced level of effort for the diagnosis of annunciated events
- Reduced level of operator and maintainer burdens
- Positive impact on operations and maintenance staff engagement

6/ RISKS (see Attachment D for details)

		Low = 1 to 3	Medium = 4 to 9		High = 10 to 25	
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Underestimation of the effort required for engineering	Preliminary engineering (PE) work was structured to reduce the risks for detailed engineering (DE). The detailed breakdown of engineering activities provides assurance for the cost estimates. A [redacted] contingency (*to be released only if justified and approved*) has been included on the overall estimate.	16	20	12	8	4	4	0	8	20	6	9	6	6	3	3	0	6	9
During the engineering activities, the scope of work expands.	PE work was structured to reduce the risks for DE. The scope of engineering has been well defined by involving stakeholders early on in the process to ensure all significant issues are being addressed. A [redacted] contingency has been included on the overall estimate.	20	25	15	10	5	5	0	10	25	6	9	6	6	3	3	0	6	9
Unavailability of internal or external staff with the required qualifications.	This is a multi-year project and key resources have been identified early on to help assure their availability. Allowances for training inexperienced staff and the higher cost of external staff have been factored into the estimates.	20	25	20	10	5	5	0	10	25	6	9	6	6	3	3	0	6	9
Unforeseen technical, quality assurance and/or human factor issues.	PE work was structured to reduce the risks for DE. Experience from past DNGS SDS projects has been utilized in preparing the schedule and estimates. A [redacted] contingency has been included on the overall estimate.	25	25	20	10	15	5	0	10	25	6	6	6	6	3	3	0	6	6

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
	Impact				
	1	2	3	4	5
Probability 5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Unforeseen regulatory requirements/issues.	The CNSC was provided with an overview of the project objectives during preliminary engineering and will be kept informed throughout the remainder of the project. Allowances for addressing their concerns have been factored into the estimates.	12	12	12	6	9	3	0	6	**12**	2	2	4	0	2	2	0	4	**4**
Normal Health and Safety concerns.	All project work will be conducted in accordance with all legal, OPG corporate, OPG Nuclear, and site safety programs.	2	2	0	4	2	4	0	0	4	0	0	0	2	1	1	0	0	2

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Nov 2013	Dec 2014	Manager, Performance Engineering DNGS

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Spare Parts/Obsolescence Indicator	Red* (2008 Q2 & Q4)	Green	System Health Report Indicator	SDS Computer SEs / Performance Engineering
2.	Monitor Computer Failures	26 Failures (2008 Q2 & Q4)	Eliminate operator workarounds and system deficiencies. Hardware meets Monitor Computer unavailability requirements.	System Health Report Indicator	SDS Computer SEs / Performance Engineering
3.	Portion of Display/Test Packets Processed	~33%	100%. Monitor Computer to process all Display/Test packets received.	Performance Tools	SDS Computer SEs / Performance Engineering
4.	CRT/VDG Failures	22 Failures (2008 Q2 & Q4)	Eliminate display quality issues. Hardware meets Display/Test Computer unavailability requirements.	System Health Report Indicator	SDS Computer SEs / Performance Engineering
5.	Operability	Current Monitor Computer (MC) systems and documentation are adequate	No reduction in operability. All operator documentation available.	All operations procedures in place.	Operations stakeholder
6.	Maintainability	Control Maintenance staff are able to support the MC systems	No reduction in operability. All control maintenance documentation available.	All control maintenance procedures in place, along with manuals, drawings and spare parts.	Control Maintenance stakeholder

* Currently, the actual rating in both the SDS1 Computers System Health Report and SDS2 Computers System Health Report is White. However, these ratings have been progressed from Red to Yellow to White over the past three years only because the DNGS SDS Aging Management Project "adequately addresses the spare parts and obsolescence issues".

Appendix "A" Glossary (acronyms, codes, technical terms)

Acronym/Term	Definition
channel	The basic unit of an SDS. Both SDS1 and SDS2 employ a triplicated channel architecture to implement the required functionality.
CNSC	Canadian Nuclear Safety Commission (the regulator).
CRT	Cathode Ray Tube (a video display)
DEC	Digital Equipment Corporation, the manufacturer of the SDS2 Trip Computers.
Display/Test Computers	Computer systems making up the intermediate layer of the SDS computer network. There is one Display/Test Computer per channel per SDS per Unit (for a total of 24), providing a facility to display critical SDS parameters and to test the safety-related functionality of the SDS via the Monitor Computers.
EPROM	Erasable Programmable Read Only Memory
GA	General Automation, the manufacturer of the Display/Test and Monitor Computers and the SDS1 Trip Computers.
MAD	The SDS Maintenance and Development facility located in Room S-341 that provides the means for off-line testing and commissioning of SDS hardware and software.
Monitor Computers	Computer systems making up the layer of the SDS computer network closest to Operations staff. There is one Monitor Computer per SDS per Unit (for a total of 8), providing a facility to test the safety-related functionality and monitor the status of the SDS.
OEM	Original Equipment Manufacturer
SDS	Shutdown System
SDS1	Shutdown System 1. A unitized system which uses neutron absorbing "shutoff" rods to rapidly shutdown the reactor due to an abnormal condition.
SDS2	Shutdown System 2. A unitized system which uses neutron absorbing "poison" (gadolinium nitrate) to rapidly shutdown the reactor due to an abnormal condition.
SSMC	Shutdown System Monitoring Computer. Note that this is not the SDS1 or SDS2 Monitor Computer. It is a single computer which collects data from all 8 SDS1 and SDS2 Monitor computers.
Trip Computers	Computer systems making up the layer of the SDS computer network closest to the "field". There is one Trip Computer per channel per SDS per Unit (for a total of 24), providing a facility to automatically monitor critical SDS parameters and initiate a reactor shutdown if conditions warrant.

Appendix "B" Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2007	2008	2009	2010	2011	2012	2013	Later	Total
Developmental	Nov	2006	345	1,438							1,783
Full	May	2009		-549	1,323	3,694	5,548	3,058	2,005	330	15,409
											0
											0
											0
											0
											0
											0
LTD Spent	Apr	2009	244	990	198						1,432

Comments:

Appendix "C" Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	2%	SR & D Opportunity	No
Progress Payments	No	Foreign Currency	No	Retainer Fee	No
Income Tax Rate	Generation	PST	No	Interest Rate (Capital)	6%
Depreciation Rate (Capital)	Office, Misc Equipment 20%	Leasing	No	Indexed Priced Contract	No

Comments:

Project Cost Estimate:

Design Complete	Up to ~ 15%	Quality of Estimate	Release + 15% to - 10%	3rd Party Estimate	No
Reviewed by Sponsor	Yes	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	Yes	Budgetary Quote(s)	Yes	First Unit Actual Used	No
Cost Sharing	No	Contracts in place	No	Competitive Bid	No
Fixed Price Contract	No	Fee for Service	No	Firm Vendor Proposal	No

Comments:

Rationale for Cost Classification:

The existing equipment is obsolete and much of it has reached the end of its useful life. The proposed upgrades will improve system performance.

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)						
Pickering A	1	N/A	N/A	N/A	N/A							
	4	N/A	N/A									
Pickering B	5	N/A	N/A	N/A	N/A							
	6	N/A	N/A									
	7	N/A	N/A									
	8	N/A	N/A									
Darlington	1	N/A	N/A	N/A	N/A							
	2	N/A	N/A									
	3	N/A	N/A									
	4	N/A	N/A									

Comments:

There may be a need to execute some work during Darlington Unit outages, although this is seen as unlikely at the current stage of the project.

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Impact on Revenue

$ Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate MWH	58.36	52.98	54.58	54.58	56.23	56.23	57.93	57.93		
Probability						80.0%			10.0%	45.0%
Consequence						(203)			[illegible]	(553)
Risk						(163)			(86)	(249)
Other										0
Base Case	0	0	0	0	0	(163)	0	0	(86)	(249)
Probability										0.0%
Consequence										0
Risk										0
Other										0
Recommendation	0	0	0	0	0	0	0	0	0	0
Net Impact	0	0	0	0	0	163	0	0	86	249

Comments:

See NPV Calculations for Details and Summary

Impact on OM&A

$000's	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A										0
Outage OM&A										0
Project OM&A										0
Base Case	0	0	0	0	0	0	0	0	0	0
Base OM&A										0
Outage OM&A										0
Project OM&A										0
Recommendation	0	0	0	0	0	0	0	0	0	0
Net Impact	0	0	0	0	0	0	0	0	0	0

Comments:

See NPV Calculations for Details and Summary

DNGS SDS Computers Aging Management 16 - 33955

Full Release Business Case Summary D - BCS - 68000 - 10002 – R001

Attachment "A" **Project Cost Summary**

	$000's Capital	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnt & Support	125	200	800	800	699	200	250		3,074
	Engineering	1,034	855	1,800	1,955	1,401	100			7,145
	Procurement	32	[redacted]							
	Construction	-	[redacted]							
	Other	3	[redacted]							
										-
										-
										-
										-
	Interest (Capital Project Only)	40	95	244	503	643	395	42		1,962
	Project Costs	**1,234**	[redacted]							
	General Contingency	-	[redacted]							
	Specific Contingency	-								-
	Project Costs	**1,234**	**1,323**	**3,694**	**5,548**	**3,058**	**2,005**	**330**	**-**	**17,192**
Cash	Adjust to Cash Basis + / -								-	-
	Project Costs	**1,234**	**1,323**	**3,694**	**5,548**	**3,058**	**2,005**	**330**	**-**	**17,192**
Funding	Currently Released	1,783								1,783
	This Release	(549)	1,323	3,694	5,548	3,058	2,005	330		15,409
	Future Release								-	-
	Project Funding	**1,234**	**1,323**	**3,694**	**5,548**	**3,058**	**2,005**	**330**	**-**	**17,192**

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

		LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Budget	2009-2013 Business Plan	1,300	1,150	5,000	5,000	5,000				17,450
	Variance to Business Plan	(66)	-	(1,756)	(110)	(2,257)	1,795	292	-	(2,102)
Other	Removal Costs included above									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

The estimated variance(s) to the 2009-2013 Business Plan will be addressed through the portfolio management process.
A PCRAF will be approved by Sep 2009.

Reviewed By: 2009-06-09

Mike Viola
Project Manager

Date

Approved By:

Rick Hohendorf
Strat IV Manager

Project Name 16 - 33955

Full Release Business Case Summary D - BCS - 68000 - 10002 – R001

Attachment "B" **Project Variance Analysis**

		LTD	Total Project		Variance	Comments
			Last BCS	This BCS		
		N/A	N/A	N/A		
		N/A	N/A	N/A		
Scores Basis	Project Mgmnt & Support				0	
	Engineering				0	
	Procurement				0	
	Construction				0	
	Other				0	
					0	
					0	
					0	
					0	
	Interest (Capital Project Only)				0	
	Project Costs (Scores Basis)	0	0	0	**0**	
	General Contingency				0	
	Specific Contingency				0	
	Project Costs (Scores Basis)	0	0	0	**0**	

Other	Removal Costs included above				0	
	Inventory to be written off				0	
	Spare Parts in Inventory				0	

Comments:
The Project Variance Analysis is not applicable (N/A) since this BCS is not requesting a superseding release.

Attachment "C" Milestones and In Service Declarations

Key Milestones

Completion Date			Description
Day	Mth	Yr	
30	SEP	2009	Project Execution Plan (PEP) approved
31	DEC	2009	Design Plan (DP) authorized
30	JUN	2010	All Project planning and procedural documents issued
30	JUN	2010	PO issued for SDS1/SDS2 Display/Test monitors
30	SEP	2010	PO issued for SDS1/SDS2 Monitor Computer equipment
30	SEP	2010	PO issued for SDS2 Trip Computer EPROM Board design modifications
30	JUN	2011	SDS1/SDS2 Display/Test Computers – Monitors – Design ECs approved
31	DEC	2011	SDS1/SDS2 Monitor Computers – Station Common Hardware and Software – Design ECs approved
31	DEC	2012	SDS2 Trip Computers – DEC Board Engineering and EPROM Board Modifications complete
31	DEC	2012	SDS1 Monitor Computers – Hardware and Software – Design ECs approved
31	DEC	2012	SDS2 Monitor Computers – Hardware and Software – Design ECs approved
31	DEC	2012	SDS1/SDS2 Monitor Computers – SDS Gateway Software - Design ECs approved
30	JUN	2013	SDS2 Trip Computers – DEC Board Emulators – Preliminary Engineering complete
-	-	-	For AFS's, see In Service Declarations table, below
30	JUNE	2014	Project Closeout

A Project Execution Plan (PEP) **will be approved by Sep 2009**

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%
JAN	2012	SDS1 Display/Test Computers – 1st Unit Monitors	754	4.4
JAN	2012	SDS2 Display/Test Computers – 1st Unit Monitors	754	4.4
FEB	2012	SDS1 Display/Test Computers – 2nd Unit Monitors	48	0.3
FEB	2012	SDS2 Display/Test Computers – 2nd Unit Monitors	48	0.3
FEB	2012	SDS1 Display/Test Computers – 3rd Unit Monitors	48	0.3
FEB	2012	SDS2 Display/Test Computers – 3rd Unit Monitors	48	0.3
FEB	2012	SDS1 Display/Test Computers – 4th Unit Monitors	48	0.3
FEB	2012	SDS2 Display/Test Computers – 4th Unit Monitors	48	0.3
JUN	2012	SDS1/SDS2 Monitor Computers – Station Common Hardware and Software	1102	6.4
DEC	2012	SDS2 Trip Computers – DEC Board Engineering & EPROM Board Modifications complete	1017	6.0
JUN	2013	SDS1 Monitor Computer – 1st Unit Hardware and Software	5429	31.6
JUN	2013	SDS2 Monitor Computer – 1st Unit Hardware and Software	5429	31.6
JUN	2013	SDS1/SDS2 Monitor Computers – 1st Unit SDS Gateway Software	460	2.7
SEP	2013	SDS1 Monitor Computer – 2nd Unit Hardware and Software	318	1.8
SEP	2013	SDS2 Monitor Computer – 2nd Unit Hardware and Software	318	1.8
SEP	2013	SDS1/SDS2 Monitor Computers – 2nd Unit SDS Gateway Software	17	0.1
OCT	2013	SDS1 Monitor Computer – 3rd Unit Hardware and Software	318	1.8
OCT	2013	SDS2 Monitor Computer – 3rd Unit Hardware and Software	318	1.8
OCT	2013	SDS1/SDS2 Monitor Computers – 3rd Unit SDS Gateway Software	17	0.1
NOV	2013	SDS1 Monitor Computer – 4th Unit Hardware and Software	318	1.8
NOV	2013	SDS2 Monitor Computer – 4th Unit Hardware and Software	318	1.8
NOV	2013	SDS1/SDS2 Monitor Computers – 4th Unit SDS Gateway Software	17	0.1

Attachment "D"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 months)	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges **OR** Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages **OR** Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

SG Controls Retrofit 16 - 33973

Developmental Release Business Case Summary D-BCS-49100-10001-R000

1/ RECOMMENDATION:

Approval is requested for this Developmental Release of $1536k (including [redacted] contingency) Capital to complete the Definition Phase of the Standby Generators (SG) Controls Retrofit project. In this phase we will select and engage the supplier of the control systems from an evaluation of six (6) prospective vendors, complete the preliminary engineering, prepare detailed estimates and obtain approval of a Full Release Phase 1 BCS for the implementation of the project.

The business objective of this project is to address the issue of unreliability and obsolescence such that the SG System Health can be maintained as white and generation risk avoided. This will be done by installing new control systems on all four SGs. The new control technology will also provide for remote monitoring and increased diagnostic capabilities to improve maintenance programs.

SG unavailability is a violation of OPG's Operating License that would require us to shut down all units if one SG could not be made available within twenty-four hours. SG Control System components are over 20 years old, are susceptible to unpredictable failure and are no longer supported by the original equipment manufacturer. Current trends indicate that our stock of critical spare parts will be depleted in an estimated 3 to 5 years, at which time the risk of concurrent SG failures will increase significantly.

Some effort has been focused on the search for alternate suppliers of spare parts, with no success to date. Similar projects performed at Darlington (Ref D-PIR-49200-10001) and Pickering B (Ref NK30-BCS-54600-00011-R000) were reviewed, and in both cases the control systems were completely replaced because no new sources of spare parts could be identified. Project costs in both cases were also consistent with our current estimates, however a better quality estimate for the overall project cost will be developed in this phase.

At least five SCRs have been raised to document problems with the existing SG control systems, and a continued decline in reliability will result in System Health degrading from white to yellow. Replacing the control systems will increase reliability and availability of spares, to maintain the System Health white.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released		-							-
Requested Now	Developmental	-	1,041	495					1,536
Future Funding Req'd	Full			1,155	4,406	7,100	3,740		16,401
Total Project Costs		-	1,041	1,650	4,406	7,100	3,740	-	17,937
Ongoing Costs									-
Other Costs									-
Grand Total		-	1,041	1,650	4,406	7,100	3,740	-	17,937

Investment Type	Class	NPV or IEV	IRR	Discounted Payback
Sustaining	Capital			

Submitted By:

15 Dec 2006
M. Arnone
Director, Projects and Modifications
Date:

Finance Approval:

Dec 14, 2006
R. Leavitt
Director Investment Management
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

15 Dec. 2006
S. Seedhouse
Director, Station Engineering
Date:

2/ BACKGROUND & ISSUES

Over the past few years, it has become evident that various control and monitoring components for the four Standby Generators (SGs) were obsolete. Manufacturers of the original components no longer provide replacement parts or service the equipment. In some cases these manufacturers no longer exist. At this time, there is a stock of critical spare parts but it is anticipated that within 3 to 5 years, this stock will also be depleted.

The known affected control and monitoring components are:

- Woodward Governor (some spares are available, calibrator parts are not available and neither technical nor parts support are available).
- Bentley Nevada Vibration Monitor (some parts are in stock and neither technical nor parts support are available).
- Rochester Annunciator (no spare parts in stock, neither technical nor parts support are available).
- Airpax Over Speed Unit (some spare parts in stock, manufacturer no longer in existence).
- Protection relays

The health status of the SGs is white (declining towards yellow). The system health reports have listed several SCRs which indicated that power supply circuit breakers have been found open, resulting in start failures or unavailability problems. The new control system would facilitate the early detection of these and other problems.

If the control system were to fail, the associated SG would be rendered unavailable. Repairs under such forced outage conditions could take several months to complete. If another SG were to fail during this time period or be unavailable due to scheduled maintenance or forced outage, the two remaining SGs must remain in the standby utdown state. If only two SGs are available, the SGs must be placed in their preferred SG line-up with respect breaker selections per NK38-OM-49100-4.12, ODD/EVEN SG selection.

Although the minimum requirement per OP&Ps is one SG, maintaining the effectiveness of Class III Transfer System requires a minimum of two SGs to be available. At least one must be selected to the ODD bus and at least one to the EVEN bus. The Class III Transfer System will first pick up the mandatory nuclear loads to ensure a safe shutdown state is maintained (one SG can carry these). The economic loads will then be picked up. The second SG is needed to pick up the significant economic loads. Failure to pick up economic loads such as the turning gear auxiliaries and the Irradiated Fuel Bay, which will then begin to heat up, could result in damage to other station systems.

Several SCR's (D-2006-01672, D-2006-01413, D-2006-01821, D-2003-03331, D-2006-08173) document problems with the control system. The following significant issues were noted in the SCRs:-

- D-2006-01672 – Numerous alarms were identified on SG1 in February 2006. At the time SG3 and SG4 were already unavailable, resulting in 3 SGs being unavailable.
- D-2006-01413 – During a test run of SG3 in February 2006, the auto synchronization failed. The synchronization was done manually. During the second run-up SG3 tripped on high vibrations and was declared unavailable.
- D-2006-01821 – In February 2006, A low vibration indication was found on SG4 vibration probe. A vibration probe was ordered for installation during the upcoming outage. This was not possible because the required parts were unavailable.
- D-2003-03331 – In April 2003 the overspeed unit in SG2 was repaired by the manufacturer by obtaining a damaged board and replacing the burnt resistors, old capacitors and bad zener diode. This is a common problem for this board. The manufacturer questioned the wisdom of investing time and money in trying to extend the life of these units as opposed to replacing the whole system.
- D-2006-08173 – In September 2006 SG3 tripped on generator protection. The 21B phase back-up relay, which has a history of spurious operation and the 64 ground fault relay were found to be tripped.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$(	Do Nothing	Alt 1 (Recommended)		Alt 2 Delay	Alt 3 2 SGs Only	Alt 4	Alt 5	Alt 5
		Full Cost	Incremental Cost					
Revenue								
Project Cost	N/A	18,000	18,000	N/A	12,000			
NPV (after tax)								
Impact on Economic Value								
IRR%								
Discounted Payback (Yrs)								

Do Nothing **(Not Recommended)**

This alternative is not recommended because failure to improve reliability and maintainability of the SG Control System will not satisfy the requirements set out in the station OP&P and the Safety Report. SG Control System components are over 20 years old, are susceptible to unpredictable failure and are no longer supported by the original equipment manufacturer. Current trends indicate that our stock of critical spare parts will be depleted in an estimated 3 to 5 years, at which time the risk of concurrent SG failures will increase significantly. Continued operation under current conditions would lead to partial or complete failure of stand by Class III power.

Alternative 1 – Replace All The Control Systems **(Recommended)**

We recommend the replacement of all the control systems, because complete replacement of the control systems would guarantee the reliability of the SGs for the remaining life of the station. This consideration and the need to maintain the reliability and availability of the SGs within the limits set by the reliability model for safe operation of the station, favour a complete replacement of the control systems for all SGs.

Replacing the existing SG control systems will improve reliability and eliminate obsolescence issues by providing the following:

- Reliable and proven control systems that are of more recent design, with readily available parts and technical support.
- Increased diagnostic capabilities and remote monitoring of generators by the system engineer to ensure that preventive maintenance and surveillance programs are effective.
- A reduction of the incidence of start failures as per the reliability model for safe operation of the station, over the remaining life of the station.

This direction is consistent with similar projects performed at Darlington (Ref D-PIR-49200-10001) and Pickering B (Ref NK30-BCS-54600-00011-R000). Our current estimate for this alternative is also consistent with the project costs for both of these comparable cases. A better quality estimate for the overall project cost will be developed in this phase.

Alternative 2 - Delay Project - Not Recommended

recommended because all the SGs are of the same age and the anticipated problem of spare parts unavailability in 3 to 5 years could result in all four SGs being unavailable at the same time. Any further delays to the project schedule will result in an increased risk of concurrent SG failures.

Alternative 3 - Replace The Control Systems On Only Two SGs (Not Recommended)
Replace the control systems in only two of the four SG's, and salvage the removed components to increase the inventory of spares for the remaining two SG's.

This alternative is not recommended because:

- The reliability gains will be less than the recommended alternative.
- The cost of this alternative is marginally less than the recommended alternative, with continued reliability and maintainability issues with the unmodified SGs.
- Operating and maintaining two pairs of SGs with dissimilar control and diagnostic systems will introduce new issues and challenges for configuration management, documentation, maintenance procedures and training.

Alternative 4 - Compile Substitute Parts From Alternate Suppliers (Not Recommended)

Search for available parts from any suppliers and continue to repair the control systems until the end of life of the station. This approach is not recommended because the Darlington Scope Review Team already investigated the possibility of purchasing substitute parts from any available vendors, whether or not they are already approved by OPG. The intention was to diligently explore the possibility of identifying available parts anywhere in the world and subsequently try to approve such vendors through the normal OPG process. There has been no success to date with this approach. While this approach may have been economically viable, assuming that all other problems associated with the age of any available parts and the age of the systems themselves, could be overcome, no parts have been located up to this point in time.

Similar problems were encountered with the Darlington Emergency Power Generators (EPGs) and the Pickering B SGs. In both cases the control systems were completely replaced (Ref D-PIR-49200-10001 and NK30-BCS-04600-00011-R000 respectively).

4/ THE PROPOSAL

The developmental release will be used to select and engage the preferred supplier through competitive process, complete the preliminary engineering, prepare estimates and obtain Full Release Phase 1 BCS.

This release will deliver the following:

- The Modification Outline, Design Scoping Checklist, Design Plan and Modification Design Requirements.
- Technical Specifications
- Issue RFP and evaluation of proposals from up to six prospective vendors
- Retention of preferred supplier
- Complete preliminary engineering
- Preparation of quality estimates
- Full Release (Phase 1) BCS

5/ QUALITATIVE FACTORS

- Increased diagnostic and remote monitoring capability will assist in establishing effective preventive maintenance programs and early detection of potential problems.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Expenditure may exceed released funds.	Cost overrun	Medium	Deliverables are clear; estimate is based on internal staff doing the work and good estimates are in hand; [redacted] contingency has been allocated for this phase of the project to ensure expenditure does not exceed the release limit.	Low
Scope				
Scope of this Phase may increase based on discussion with vendors	Schedule and cost overrun	Medium	The scope of this phase is defined and scope increase is unlikely, however, [redacted] contingency has been allocated.	Low
Schedule				
Schedule for completing the milestones may be delayed due to lack of resources	Schedule and cost overrun	Medium	Appropriate resources have been identified (eg. DNGD Projects Design. CCD - DNGD DCC) and will be used as soon as funding is released. [redacted] contingency has also been allocated.,	Low
Resources				
Lack of experienced engineering resources for this Phase of the project	Delay in completion of this Phase	Medium	Appropriate resources have been identified and their availabilty confirmed (e.g.DNGD Projects Design, CCD - DNGD DCC) and will be used as soon as funding is released. [redacted] contingency has also been allocated.	Low
Technical				

None				
Regulatory				
None				
Environmental				
None				
Health & Safety				
None				
Investment				

11 POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
N/A	N/A	N/A	N/A

Comments:
N/A for this phase.

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Appendix "A" **Glossary** (acronyms, codes, technical terms)

SG - Standby Generator
SCR - Station Condition Record
CCD - Computer Control Design
DCC - Digital Control Computers
PEP - Project Execution Plan
PCRAF - Project Change Request Authorization Form
OP&P - Operating Policies and Principles

Appendix "B"

Project Funding History

$ 000's Release Type	Month	Year	Timing of Funding Released (incl contingency) 2005	2006	2007	2008	2009	2010	2011	Later	Total
											0
											0
											0
											0
											0
											0
											0
											0
LTD Spent	May	2006	0	0	0	0	0	0	0	0	0

Comments:
Conceptual Funding of $135k was approved by the Director of Projects and Modifications in November 21, 2005.

Appendix "C"

Financial Model – Assumptions

Project Cost Assumptions:

Conceptual Estimate +60% to -25%
See Basis of Estimate (Attachment A)

Financial Assumptions:

Project / Station End of Life Assumptions:

2018

Energy Price / Production Assumptions

Operating Cost Assumptions

Other Assumptions:

SG Controls Retrofit 16 - 33973

Developmental Release Business Case Summary D-BCS-49100-10001-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2006	Dev Release 2007	Dev Release 2008	Future Release 2008	Future Release 2009	Future Release 2010	Future Release 2011	Later	Total
Project Management (OPG)		138	79	70	170	170	170		797
Engineering & Drafting (OPG)		315	162	400	420	360	100		
Material	[redacted]								1,757
Installation – PWU, BTU	[redacted]								
Contract - Design									
Contract - Installation									
Contract - Other									
Contract - Software & HFE									
Interest (Capital Project Only)									
Project Spending									
Committed Cost									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	-	1,041	495	1,155	4,406	7,100	3,740	-	17,938
Ongoing OM&A (non-project)									
Inventory Write Off Required									-
Spare Parts / Inventory									-
Grand Total (incl contingency)	-	1,041	495	1,155	4,406	7,100	3,740	-	17,938
2006-2010 Business Plan	1,500	3,500		3500	3,000	2,850	-		14,350
Variance to Business Plan	(1,500)	(667)	(3,104)	924	525	2,830	2,992	-	-

Removal Costs (incl in above)									-

Basis of Estimate	**+60% / -25%**				
Design Complete	No	Contracts in place	No	Competitive Bid	No
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	No	Sponsor Cost Estimate	No	Phase 1 Actual Used	No

Other:
Variances to 2006 Budget and 2006 -2010 BP will be addressed through the portfolio management process.

Reviewed By: 14 Dec 2006
...n Cvitkovic
Project Manager
Date:

Approved By: 14 Dec 2006
Terry Chong
Eng & Mods Manager (Strat IV)
Date:

SG Controls Retrofit 16 - 33973

Developmental Release Business Case Summary D-BCS-49100-10001-R000

Attachment "B"

Project Variance Analysis

Choose One	LTD Choose Choose	Choose One Last BCS N/A N/A	This BCS N/A N/A	Variance	Comments
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material	[redacted]				
Installation – PWU, BTU					
Contract - Design					
Contract - Installation					
Contract - Other					
Interest (Capital Project Only)					
Project Spending					
Committed Cost					
Project Costs (excl contingency)					
General Contingency					
Specific Contingency					
Project Costs (incl contingency)	0	0	0	0	
Ongoing OM&A (non-project)				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Grand Total (incl contingency)	0	0	0	0	

Comments:

No previous release. Not required

ttachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
02	Sep	07	Major Contract Awarded (MCA)
14	Feb	08	Preliminary Engineering (DES)
30	May	08	Full Release (Phase 1) BCS

Comments:

A Project Execution Plan (PEP) will be approved by September 2007

Darlington DCC Replacement 16 - 33977

Full Release (Phase 1) Business Case Summary D-BCS-69100-10001-R001

1/ RECOMMENDATION:

We recommend an additional release of $16.0M ($22.1M total including contingency) for the Darlington Digital Control Computer (DCC) Replacement Project.

The business objective of this project is to avoid a shutdown of a unit due to the unavailability of the CPUs in a dual DCC configuration due to either a component failure or a lack of available spares. A shutdown of this nature would be lengthy as a replacement DCC would have to be engineered and installed. This objective is consistent with the Darlington DCC Life Cycle Strategy as defined in NK38-REP-69000-10001.

The existing DCC hardware is obsolete and will not operate for very much longer with the required system availability. An associated project (Replacement of Obsolete Computer Components 33509) has been successful in replacing some of the subsystems (memory, power supplies, mag tape units etc) whose reliability or maintainability was threatening the overall DCC performance. However the limit of useful subsystem replacement has been reached and it is necessary to replace the core of the DCC system.

A partial release of $6.1M was approved in Sep 2003 to replace the Sequence of Events (SEM) and Common Processes (CP) computer, and perform initial preliminary engineering for the replacement of the Darlington DCC's. At the time, it was assumed that we could use "off the shelf" PDP-11/70 emulators for all 3 applications. However, after spending $1.2M of the current release, to complete the preliminary engineering (including the "design challenge" process) we have identified serious design issues that prevent the use of "off the shelf" technology in a nuclear control application.

We are now recommending the re-design of an existing PDP emulator from Quickware, with QA oversight from an independent and external source. Although the need to redesign (with oversight) has driven the estimated cost of the project from $14.8M to $22.1M, a rigorous RFP process has determined this to be the most viable and cost effective solution for all 3 applications. Moving to a full release at this time will allow us to keep costs down and ensure compatibility amongst the 3 systems. (See Attachment B for details).

This project is listed in the 2006-2010 Business Plan at $82.2M; with $15.5M allocated for this work and $66.7M targeted for DCC replacement under a Life Extension program beyond 2010. This funding request is intended to sustain the operation of the control computers until retubing takes place. Only minimal functional improvements will be made. This request is consistent with the 2006 Budget; however, changes in the estimate for the 2007 to 2011 timeframe will need to be addressed in the next Business Plan. A Project Execution Plan (PEP) will be approved by ~~19-May-2006:~~ 2 Jun 2006.

31 May 06

$000's Capital		Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Full (Phase 1)	6,050	5,261	Mar-06	Spent Life to Date:	1,231
Requested Now:	Full	16,006	13,921	2006-2010	Appr'd Business Plan (Tot Proj):	15,521
Cumulative Release:	Total to Date	22,056	19,182	2006-2010	Business Plan Variance:	3,661
Total Project Estimate:	+30% to -15%	22,056	19,182	2006	Budget (Current Year)	2,727
Current Year Estimate:	2006	3,134	2,726	2006	Budget Variance (Current Yr)	(1)
Type of Investment:	Sustaining	N/A	N/A	Cumulative Release Remaining:		17,951
NPV:			N/A	Contingency on Remaining Release:		2,876
IRR:			N/A	Contingency % on Remaining Release:		16.0%

Submitted By:

P R Charlebois
EVP and Chief Nuclear Officer Date:

Finance Approval:

D. Power
Director Investment & Business Planning Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

J. Hankinson
President & CEO Date:

2/ BACKGROUND & ISSUES

Darlington DCCs

Project 33977 addresses several issues, which present risk to the continuing performance and operation of the Darlington Digital Control Computer (DCC) systems:

- Hardware obsolescence. The current computers are of obsolete 1970s technology (DEC PDP11 minicomputers).
- Diminishing support from the industry. There is no OEM support and, unlike other CANDU stations, the hardware and software used at Darlington are unique. The few manufacturers of PDP emulators are ceasing production, and PDP expertise is disappearing quickly.
- The availability of spare parts in the marketplace has dwindled to a very small number of suppliers, and the quality and history of available spares is questionable.
- Certain key components, such as computer backplanes, are prone to wear out as a result of troubleshooting activities. This situation will deteriorate with time. The backplanes ~~are~~ cannot be reproduced.
- Pending shortage of in-house engineering resources. Large numbers of the original design team are eligible for retirement.
- The skill set required to repair the PDP equipment is disappearing, and the skills are not taught in trade schools.

The business case for the initial release for project 33977, approved in 2003, requested funding in the amount of $6.05M, including contingencies, and provided for the replacement of the five Sequence of Events (SEM) Computers and the Common Processes Computer (CP). The business case indicated that approval of a further amount, then estimated at $8.7M, would be requested later (in approximately 3 years) when a path forward was confirmed. This further funding would be required to complete the replacement of the Unit Computer DCCs and the Ramtek Display systems.

A highly skilled team, following a rigorous Software Quality Assurance (SQA) program, undertook the original design of the Darlington control software. This represents an enormous investment, both financially, and in expended time. Any attempt to recreate the software using modern Operating Systems and computer platforms would be extremely expensive and time consuming. Thus, at present, only solutions to the DCC maintenance and support issues that enable the investment in the control software to be retained are being considered.

At Darlington NGS, computers are used in Sequence of Event Monitoring Systems, the Common Processes monitoring System, the Unit DCCs and the Fuel Handling systems. All these systems use models from the Digital Equipment Corporation (DEC) family of PDP11 processors. Although this family was popular at the time of the Darlington engineering design, in the early 1980s, it is believed that Darlington represents the only instance in which this type of computer is used in a nuclear control application.

The provision of replacements for the Digital Equipment Corporation (DEC) line of processors is a specialty and declining field. Basically there are two types of replacement products:

- Hardware emulators, in which the instruction set of the original PDP11 is emulated in the replacement computer, using modern custom-designed hardware to replace the functions of the DEC equipment.
- Software Emulators, usually based on a PC platform, using a commercial, or custom operating system. The original DEC computer language is emulated by the PC, using the software resident in the "host computer".

Hardware emulators are relatively complex to design, and require considerable engineering knowledge and understanding of the operation of the original DEC computer hardware, and peripherals. While using modem technology, they do, however, provide for an almost exact emulation of the performance of the original DEC computer. As such, this would allow the transfer of the existing DCC control software to the emulator, with minimal issues with respect to instruction timing, while maintaining compatibility with the existing peripherals.

An RFP process was Initiated, which identified Quickware as the most viable and cost effective provider of a hardware-based PDP Emulator, suitable for use in the Darlington DCCs. (Quickware has already provided an earlier model of hardware emulator used in the Fuel Handling systems at Darlington.) Subsequently an OPG internal design challenge process was initiated, which resulted in the development of a detailed design specification for the hardware emulator. The recommended approach will involve re-design of the original Quickware product to meet the additional requirements for operation in the Darlington DCCs.

At the time of the initial release of funds it was assumed that an "off the shelf" product would be able to replace the original DEC computers. However the detailed engineering performed under the initial release of funds identified serious design issues in the available off the shelf emulator products that would prevent their use in a nuclear application. The re-design of the Quickware project, under the oversight of a rigorous QA program, has been identified as the most cost effective and risk free approach. The cost estimate refinement resulting from the preliminary engineering activity, plus the identified increased engineering work due to the unavailability of a suitable existing product has resulted in an increase in estimated project costs from $12.9M to $19.2M.

Ramtek Display Systems

Under the initial release for project 33977, an experienced software consulting company determined that replacement of the existing aging display generators by modem compatible is feasible. The analysis also identified that the phased implementation of a replacement display system on the DCCs at power would be complex, and would best be carried out in conjunction with a future unit outage. It is therefore recommended that the Ramtek replacement should be first implemented in the SEM and CP systems.

Required Annunciation Improvements

Operational Experience Review of CANDU stations including Darlington Nuclear Generating Station, has demonstrated that original control room annunciation design does not fully support current operational goals and user needs in the main control room across all plant states. Improvements to the Darlington MCR Annunciation System (SCI 60312) are needed to improve alarm conditioning to inhibit nuisance alarms, which occur during reactor start-up/shutdown and during, upsets.

Specific assessments of the Darlington Loss of Bulk Electrical System (LOBES) upset and outage related Operational tasks (i.e. Shutdown and startup, equipment out-of-service declaration) were conducted to characterize the annunciation system deficiencies and user needs. The Annunciation Improvements segment of Project #33977 will focus on the elimination of the identified conditioning and suppression deficiencies. Further, the Darlington Authorized Training Section has identified Turbine Trip as another upset that has excessive Operator workload demands due to Annunciation deficiencies analogous to the LOBES event. These nuisance alarms will also be addressed.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Stop the Project (Not Recommended)

Stopping the project is not a viable option. The life limiting components at this point are the availability of the CPU backplane and the floating-point processor. Currently, the entire supply of healthy spares has been used. This is especially true for the CPU backplane. It is "wire wrapped" and the board contacts are made mechanically. The probability of these components breaking down will increase with time, in proportion to the number of card re-insertions, typically made during "troubleshooting". Another important factor is that, most likely, the members of the original DNGS design team, as well as the currently available hardware vendor will become un-available in the next 3-5 year timeframe, since the market demand is small and the existing experts in the technology are aging. "Stopping the project" now will cost the corporation considerably more in the future, as the result of eliminating the most economical and risk-free option.

Unavailability of the CPUs in a dual DCC configuration, due to either component failure, or lack of available spares, would cause a complete shutdown of that unit, with associated loss of production. The shutdown would be lengthy, until a replacement DCC could be engineered and installed.

Alternative 1 – Replace the PSP11 Computers in the DCCs by a Hardware Emulator (Recommended)

The preliminary engineering work, performed under the initial release of funds for this project, has identified a suitable hardware-based emulator, for use in the Sequence of Events (SEM) systems, the Common Processes (CP) system, and the DCCs. The proposed product is from the same company (Quickware) that supplied the emulators currently in use in the Fuel Handling Systems at Darlington NGS. Re-design of the product is required, and this work, by the vendor, should proceed, with QA oversight provided by another company (L-3 MAPPS) to minimize long-term support risks.

- Hardware emulation is accepted by the CNSC as a "low risk" replacement technique, thus no regulatory approval is likely to be required.
- L-3 MAPPS, who have submitted a joint proposal with Quickware, have a history of providing equipment and support to OPG (as CAE).
- L-3 MAPPS is developing nuclear support as a long-term corporate goal, and have received a long-term contract for the supply of a Varian Computer emulator, and associated long-term support, from the COG organization.
- L-3 MAPPS has the capability to continue the design effort associated with the PDP11 emulator design, testing and production, should unforeseen issues affect the capabilities of the Quickware organization.
- The QED 95, developed by Quickware, is currently in use on the Fuel Handling Systems at Darlington. (Note: this product can no longer be manufactured, due to obsolescence of certain parts, and also has limitations that would prevent its use in the Darlington DCCs).
- The Quickware organization has the capability to adapt the design of the redesigned emulator to address OPG technical concerns with respect to failure modes, error checking and detection, and packaging. The design can also utilize successful OPG initiatives, completed under project 33509, to resolve obsolete DCC equipment issues (e.g. power supply replacements).

A hardware-based emulation solution has a lower risk of issues developing with respect to compatibility with existing control software, than with a software emulator. This is consistent with the approach successfully used to replace the DCCs at Pickering A.

Alternative 2 - Delay the Recommendation (Not Recommended)

Action on this issue has already been delayed to the point where the availability of the most economical and least risky alternative could disappear. Further delay would lead to a level of DCC performance risk that is unacceptable to the overall objectives of OPG. In addition, experienced Darlington staff members who are critical for the success of the project will be lost due to retirement in the next few years. As well, the number of potential suppliers will also diminish as the demand for PDP11/70 compatible products declines. The cost of doing the project (if at all possible) will be substantially higher.

Alternative 3 - Do Less (Not Recommended)

The do less option involves the "piecemeal" replacement of equipment in the Darlington DCCs in order to resolve specific problems as they evolve. Project 33509, Obsolete Equipment Replacement, has already taken this approach, and has resulted in providing solutions to maintenance, and longer-term support issues associated with the memory, Moving Head Disk (MHD) Mag Tape unit (MT) and Power Supplies. Project 33509 has taken this "do less" approach to its limit of effectiveness, and now the maintenance and long-term support issues associated with the CPUs themselves and the Display systems must be addressed.

Alternative 4 - Do More (Not Recommended)

Complete DCC Replacement by Modern Digital Control System (Not Recommended)

An alternative approach to the use of PDP emulators as replacements for the CPUs in the Darlington DCCs would be to replace the complete DCC via a modem digital control system. This would offer newer technology and better support from the industry.
However, in this approach, there are a number of significant implications:

- The DCC control software would have to be re-written, which would require a large software team, working within a rigorous QA program. This is not be required if the existing CPUs are replaced by emulators. Additionally there may be process complications in faithfully transferring the control implementation from the existing control system
- There may be high risk in obtaining CNSC licensing approval (completely new control software).
- Significant, and very costly, re-arrangement of the field wiring would be required in a complete DCC replacement.
- Unlike alternative 1, the complete replacement of the DCC by a modern digital control system cannot be performed in a staged manner, and thus an extensive outage would be required, such as that available in retubing. Planned outages of sufficient duration are not planned within the period during which DCC replacement must occur.
- This approach would be resource intensive, and would require lead times considerably longer than those for alternative 6. Thus the risks of outages due to DCC failure would increase significantly beyond 2010, if this approach were to be taken.

These disadvantages outweigh the benefits and the cost of this alternative (even if outages of sufficient duration were available) would be several times greater than of the recommended alternative, should we decide to extend the life of the station by way of a re-tubing initiative.

A complete DCC replacement by this approach is included in the long-term business planning for Darlington, with a conceptual cost of $60M. This approach would only be re-examined if a decision to extend the life of the station by retubing were made.

Alternative 5 – Other - Replace the PDP 11 Computers in the DCCs by a Software Emulator (Not Recommended)

This alternative offers comparable overall cost to the recommended alternative (hardware emulator) based on current estimates. However, even though the costs are comparable, this alternative has considerably greater technical and regulatory risks.

The system architecture would be much more complex than the current DCC implementation. It would involve three interacting systems (SimH, Operating System, and a new hardware platform). Ensuring that the fault tolerance and fault detection of a software-based emulator is equal to or better than the existing PDP 11/70, would be difficult. The nuclear regulator will likely have significant concerns since the use of a software-based emulator in a nuclear plant is "uncharted territory" and only hardware-based emulators have ever been used for DCC replacement on a nuclear unit.

- The various failure detection and handling schemes inherent in the current, PDP11 based design, would need to be re-assessed.
- Several new failure modes will be introduced by the introduction of a software emulation product, and will require significant assessment (e.g. issues with the newly introduced operating system, instruction timing incompatibilities etc.).
- The interface with the DEC Unibus is a weak point in most software emulators, and will require significant engineering and development to ensure a secure design is in place.
- There are uncertainties with respect to the discovery of new significant technical issues, as the design develops. This in turn would result in greater uncertainty and risk with respect to cost and schedule.

A detailed study was undertaken to compare the hardware and software emulation alternatives. Report NK38-REP-69100-10004, dated 10 February 2006, was produced, and concluded that the hardware emulator is the best approach based on DCC unavailability risk.

Alternative 6 – Other – Replace the Darlington DCCs using the Varian DCC emulator being produced for Pickering B and other CANDU stations as part of a COG joint project. (Not Recommended)

The Varian emulator cannot run the Darlington DCC software. Redesigning the Darlington DCC software to run on the Varian Emulator is probably infeasible, would cost several times more than the recommended alternative, and would incur substantially greater regulatory and technical risk.

Alternative 7 – Other -

4/ THE PROPOSAL

This project will replace the PDP11 computer based control systems and the display system with emulator based systems that will:

- Ensure the reliability (99.9%) of the DCC, Common Process Computer (CP) and Sequence of Events Monitoring (SEM) Computers for the current life of the station;
- Provide needed annunciation improvements;
- Prevent obsolescence and avoid shortage of spare parts;
- Provide an upgrade path for future plant life extension (beyond 20 years), if necessary.

The recommended approach is:

- Obtain a replacement as soon as possible.

  In terms of having a replacement as soon as possible with least risk, the hardware-based emulation option (Quickware/L-3 MAPPS) is the best choice. The software-based emulation approach (SimH) requires a much greater internal engineering effort as well as larger schedule and regulator risk. Hence the following is recommended:

- Keep the DCC healthy (complete the planned improvements per Project 33509). The fewer number of stalls, the fewer number of times the DCC needs to be disturbed. This will reduce the possibility of accidental damage to DCCs (especially the backplanes whose connections are made mechanically);
- Continue searching for "used" spare parts qualified for use.
- Implement the replacement as soon as possible:
  - Complete negotiations with L-3 MAPPS/Quickware to clarify and resolve the remaining price structure, and terms and conditions issues.
  - Award the contract to L-3 MAPPS for development of a PDP11 based emulator, based on enhancement of the Quickware design;
  - Complete discussions with L-3 MAPPS with respect to detailed work plans and schedules, to ensure the proposed project is adequately resourced to meet the required schedule.

Proceed with the design and procurement of an emulator for the Ramtek display systems.

Proceed with the design and implementation of Annunciation Improvements, to address nuisance alarms received during turbine trip events and during planned outages.

Milestones Finish Date (D/M/Y)	Description
2-Jun-06	Revise PEP and obtain approval
26-May-06	Award of contract for hardware emulator
15-Oct-07	Re-design of hardware emulator complete
21-Jan-08	Prototype hardware emulator available
24-Nov-08	Functional testing of emulator complete
30-Jun-09	Emulators installed in SEM systems
31-Dec-09	Emulator installed in CP
30-Jun-11	Emulator installed in DCCs
31-Dec-09	Ramtek replacement design complete
30-Jun-11	Ramtek replacement installation in DCCs
31-Dec-08	Annunciation improvement software programming complete
31-Dec-10	Annunciation improvements installed

5/ QUALITATIVE FACTORS

Completion of this project will result in more reliable DCC performance. This will result in:

- The reduction of maintenance effort.
- The elimination of spare parts shortages.
- In conjunction with project 33509, the return the health status of the DCC and CP computers to green (from yellow) and maintain them at that level.
- The improvement of the Annunciation Alarm Conditioning, eliminating the operator work-around caused by nuisance annunciation messages.
- The introduction of newer technology, which will be easier to support and maintain by less experienced staff, greatly reducing the requirement for legacy knowledge.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Unforeseen problems in redesign of hardware emulator	Development costs could increase	Medium	Use fixed price contracts wherever possible. Note:The Design Challenge has already been completed and the project scope is well defined.	Low
Unforeseen problems in design of Ramtek replacement. Note: Little preliminary engineenng has been performed in this area, therefore the risk remains.	Development costs could increase	High	Develop synergy with Fuel Handling project, which also requires a solution to the Ramtek replacement issue.I	Medium
[illegible]				
Increased project scope due to undiscovered problems occuring.	Potential increase in cost, and schedule delays. Project Charter and contracts must be re-done.	Low	Detailed design specification confirmed and agreed upon before re-design of emulator.	Low
[illegible]				
Problems occuring in re-design phase of emulator.	SEM in-service delayed. DCCs in-service possibly delayed	Medium	Negotiate contract with service providers to ensure that payment schedule encourages timely acheivement of milestones. SimH retained as back-up plan.	Low
Unforeseen problems revealed in testing of redesigned emulator.	SEM in service delayed. DCC's possibly delayed.		QA Service provider can apply additional technical resourses.	Low
[illegible]				
Loss of key staff members in design team for emulator.	Project would be delayed, but with limited cost implications. (Fixed price contracts in place with service providers).	Medium	Knowledge will be transfered to the QA service provider in the initial engineering phase. The QA service provider could then continue to manage the remaining work.	Low
Loss of experienced staff in the DCC section, due to retirement.	Project would be delayed.	Medium	Several junior engineers will be exposed to new technology on this project.	Low
Lack of HFE resources, and DCC	Schedule delayed.	Medium	Identify risk early in project. Bring in external resources	Low

resources familiar with annunciation.			if necessary.	
The company proposed for the emulator re-design work is small, with the core expertise currently residing with a single person.	Loss of a key resource could lead to a return to the preliminary design stage.	**Medium**	A second agency, L-3 MAPPS, has been commissioned to work with the emulator designer to ensure that the key design elements are captured in the event of loss of this resource.	**Low**
Emulator could include a component with a short life span that cannot be replaced.	Emulators would have to be replaced before their projected life.	**Medium**	The design challenge processs specified that only components with a reliable life span shall be used in the redesigned emulator.	**Low**
				N/A
Any software or firmware used in the emulator will have to be qualifiable to software category two.	CNSC approval process could cause delays.	**Medium**	A hardware-based emulator will be pursued to minimise software changes. This approach is easier to validate and confirm.	**Low**
No risks identified.				
No risks identified.				
The replacement does not meet the business objectives	The detailed design work must be repeated. Increased failure rate for DCC's would be likely while the re-design is performed, with possible associated production loss.	**Medium**	L-3 MAPPS commissioned to oversee the emulator re-design work, and monitor progress and achievement of intermediate design milestones.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Dec 2010	Jun 2011	E Hung Section Manager Darlington DCCs

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	DCC Emulator Passes Acceptance Test.	Existing PDP11 performance.	Funtionality demonstrated by system tests.	Suite of tests based on performance of original system.	QA oversight provider, in conjunction with Darlington DCCs staff.
2.	Emulator Functions in SEM systems, CP and DCCs.	Existing PDP11 Operation	SEM, CP and DCC S/W and H/W Check programs function normally in an extended test. Same or better operation using system utilities to measure system loading and performance.	Monitor for system stalls, and errors detected.	Darlington DCCs staff.
3.	Number of System Stalls reduced.	System Health is "White".	System Health returns to "Green".	System health reports..	System engineer.
4.	System spares situation returns to "Healthy" state.	Some parts in short supply.	Sufficient Spares to reach End of Life.	Inventory of Spares is acceptible.	Darlington DCCs/. Control Maintenance
5.	Frequency of nuisance alarms during startup and shutdown.	Established by historical data	Significant reduction in number of nuisance alarms.	Ops acceptance of reduction in alarms.	MCR system engineer

Darlington DCC Replacement 16 - 33977

Partial Release Business Case Summary D-BCS-33977-10001-R001

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Years 2005	2006	2007	2008	2009	2010	2011	2012	Total
Project Management (OPG)	238	189	189	189	189	108	81		
Engineering & Drafting (OPG)	282	678	1,370	1,183	705	303	118		1,183
Material	[redacted]								4,639
Installation – PWU, BTU	[redacted]								
Contract – Project Mgmt									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Sub Total (excl Contingency)									
Contingency									
Grand Total	1,243	[illegible]	[illegible]	4,133	4,251	3,214	492		22,034
2006-2010 Business Plan	1,175	2,727	2,800	2,631	3,415	2,973		-	15,521
Variance to Business Plan (excl Contingency)	(94)	(1)	2,234	983	309			-	5,851

Removal Costs Included in above	**0**
Definition Costs Included in above	**0**
Estimate Name, Quality, etc	**Budget Estimate +30% to -15%**
Design Complete:	**Up to ~ 15%**

Reviewed By:

E Hung — Date: May 11, 06
Project Manager

Approved By:

R Hohendorf — Date: May 17, 2006
Eng & Mods Manager (Strat IV)

Darlington DCC Replacement 16 - 33977

Partial Release Business Case Summary D-BCS-33977-10001-R001

ATTACHMENT "B" **TOTAL PROJECT COST VARIANCE TABLE**

$000's Choose One	Last Release day/mth/yr	This Release day/mth/yr	Variance	Explanation
Project Management (OPG)	1,038	1,183	145	Longer project duration
Engineering & Drafting (OPG)	3,637	4,639	1,002	Additional verification required for new product
Installation – (OPG)	257	260	3	
Material	[redacted]			
Contract – Project Mgmt				
Contract - Design				
Contract - Installation				
Contract - Other				
Interest (Capital Project Only)				
Sub Total (excl Contingency)	12,886	19,152	[illegible]	
Contingency	1,933	2,878	943	
Grand Total	14,819	[illegible]	7,236	

Calandria Vault Inspections 13 - 46537

Superseding Business Case N - BCS - 30673 - 10001 – R00

1/ RECOMMENDATION:

We recommend an additional release of **2,524k$** (including 1,091k$ contingency) to complete the deliverables for the Calandria Vault Inspection Project, bringing the total release of funds to 26,397k$.

The business objective of this Project is to develop the capability to deliver a platform for inspection and repair end effectors to all of the specified calandria vault components.

Repair capability is outside the scope of this Project.

The execution of an inspection campaign is outside the scope of this Project and is being addressed by Project 46606 – Calandria Vault Inspection Execution.

Project 46552 was initiated (developmental release) in 2005 with the major deliverables being two vendor proposals for the design and fabrication of a calandria vault (CV) manipulator arm for use as a platform for inspection and repair of CV components.

Subsequently, a full release of 23,873k$ was approved in August 2006 as Project 46537, with an expected completion date of February, 2008. In order to meet the business objective to develop the capability to deliver a platform for inspection and repair end effectors to all of the specified calandria vault components, the following set of major deliverables were included:

- 2 CV manipulator arms, with the capability to deliver a platform for inspection and repair end effectors to all of the specified calandria vault components
- Ultrasonic and video inspection end effectors for the CV manipulator arms
- Mockups for tool testing and training
- Horizontal and vertical video on extension booms to provide overview visuals of the CV internals and for field of view cameras during the CV manipulator arm operations
- Non-arm tooling including: Robotic vehicle and associated video/ultrasonic end effectors, Ion Chamber Cooling Line inspection equipment
- Site preparations for unit inspections (station assessments and modifications were not included)
- Field testing of all inspection equipment in Unit 2 (schedule permitting)
- Training and procedures
- Project management and engineering

This release did not include funding for repair capability or repair end effectors.

This superseding request is driven by a major schedule variance caused by technical design issues that the robotic arm vendor has encountered. Additional funding is required to address this cost and scope variance noted below. The status of the major deliverables on the Project, as of March 31, 2009, is also included:

Deliverables from 2006 Full Release	Redefinition of Deliverables during Project Execution and Rationale	Status (March 31, 2009)
2 CV manipulator arms, with the capability to deliver a platform for inspection and repair end effectors to all (100%) of the specified calandria vault components	○ 2 CV manipulator arms, with the capability to deliver a platform for inspection and repair end effectors to most (89%) of the specified calandria vault components. ○ A concession to the manipulator arm CV accessibility was accepted from the robotic arm vendor due to several factors.	Takeover of 2 CV manipulator arms scheduled for January 2010 (1st arm) and March 2010 (2nd arm)
Ultrasonic and video inspection end effectors for the CV manipulator arms	○ None.	In progress; 75% complete
Mockups for tool testing and training	○ Full scale CV mockup was created to test and commission full CV accessibility of manipulator arms. ○ Now used to test and commission all equipment before deployment due to cancellation of Unit 2 field test.	Complete
Horizontal & vertical video on extension booms to provide overview visuals of the CV internals and for field of view cameras during the CV manipulator arm operations	○ Common platform created for both horizontal and vertical video cameras and booms, not originally considered in 2006 Full Release	In progress; 75% complete

Deliverables from 2006 Full Release	Redefinition of Deliverables during Project Execution and Rationale	Status (March 31, 2009)
Non-arm tooling including: Robotic vehicle and associated video/ultrasonic end effectors, Ion Chamber Cooling Line inspection equipment	○ Robotic vehicle ultrasonic inspection end effectors cancelled due to redefined accessibility of personnel to associated components.	In progress; 90% complete
Site preparations for unit inspection (station assessments and modifications were not included)	○ None.	Complete
Field testing of all inspection equipment in Unit 2 (schedule permitting)	○ The schedule did not permit the use of Unit 2 for field testing. Instead, the CV full scale mockup has and will be used to test and commission all equipment before deployment in a working unit.	Not applicable
Training and procedures	○ Staff training and procedure preparation necessary to close this project will be prepared. Detailed staff training, procedures, and site preparation, required for first inspection use are covered under Project 46606 – Calandria Vault Inspection Execution.	In progress; 25% Complete
Project management and engineering	○ None.	In progress; 65% complete

Project life to date (LTD) spending, as of March 31, 2009, was 16,698k$. Project committed costs, as of March 31, 2009, were 5,378k$. The Project LTD plus committed costs, as of March 31, 2009, were 22,076k$.

The revised estimate to completion includes a 13% contingency allowance on the remaining work, re-estimated by the Project team in May, 2009. Significant Project risks have been retired since the full release in August 2006, however, there are project risks, despite mitigation, that will remain high for the duration of this Project. The remaining risks to the Project are detailed in section 6.

The completion of this Project will provide a capability to deliver a platform for inspection and repair end effectors to most (89%) of the specified calandria vault components. A significant portion of the inspection/repair platform developed under Project 46537 will be exercised under Project 46606 – Calandria Vault Inspection Execution, confirming its suitability for future inspection and/or repair campaigns.

$000's (incl contingency)	Type	LTD 2008	2009	2010	2011	2012	2013	Later	Total
Currently Released	Full	14,576	7,324	1,973					23,873
Requested Now	Superseding		544	1,868	112				2,524
Future Funding Req'd	None								-
Total Project Costs		14,576	7,868	3,841	112	-	-	-	26,397
Non Project Costs									-
Grand Total		14,576	7,868	3,841	112	-	-	-	26,397

Investment Type	Class	NPV	IRR	Discounted Payback
Sustaining	Capital	+6,178 $k	25%	5.7

Submitted By:

M. Elliott
SVP, Pickering A

Date: July 19/09

Finance Approval:

D. Hanbidge
SVP and CFO

Date: August 5/09

Line Approval (Per OAR Element 1.1 Project in Budget):

T. Mitchell
President and CEO

Date: 10 Aug 2009

2/ BACKGROUND & ISSUES

The Pickering A calandria vaults were originally designed to be vented to atmosphere through the station stack, but early in the life of the reactors these vents were sealed off to reduce station noble gas emissions. As a result, humidity levels within the stagnant vaults became high, which was worsened by chronic leakage from the biological shield cooling system within the vaults. The biological shield cooling system, which includes the carbon steel ring thermal shield (RTS), is unique to Pickering A and these systems must be in service during reactor operation to protect and maintain the integrity of concrete structures. Later designs for Pickering B, Bruce A&B, and Darlington utilize water filled Calandria Vault environment.

The combination of high humidity, air and radiation created a nitric acid environment, resulting in substantial corrosion of carbon steel components within the calandria vault of each unit. Corrosion-induced leaks in the mid-1990s required that the carbon steel RTS inlet and outlet lines be removed and replaced with stainless steel flexible hoses using remotely operated robotic equipment. The CV is an inaccessible room with high radiation fields that houses the reactor vessel and dump tank in the Pickering A units - remote tooling is the only option for inspection and repair work in this area.

Sporadic leaks from the biological shield cooling system have occurred up to the present time, with the most recent leak occurring in Unit 1 in April 2008. The leakage is being controlled presently by the application of on-line sealant, which is being added proactively on an annual basis with the hope of minimizing minor leakage into the calandria vault.

The installation of air dryers was undertaken in the early-1990s to reduce corrosion in the Pickering A calandria vaults. However, these dryers were only partially successful in maintaining the dew point below a specified value because of reliability issues stemming from the corrosive nitric acid condensate. To minimize further corrosion in the Unit 1 and 4 calandria vaults, Project 49252 is near completion to improve the reliability of the Calandria vault drying system by replacing the drying units. The new dryers were installed in Unit 4 in Spring 2009 and are expected to be installed in Unit 1 in Q3 2009.

For Pickering A units 1 and 4, OPG's Reactor Assembly Aging Management Plan has identified many components within the calandria vault to be inspected. To complete these inspections, and to implement repairs should the need be identified, remote tooling must be developed to deliver inspection and repair end-effectors to the internal areas of the calandria vaults.

Previously, approximately 660k$ was spent on Project Scoping using funding from the Pickering A Return to Service budget.

Subsequently, Project 46552 was initiated (developmental release) in 2005 with the major deliverables being two vendor proposals for the design and fabrication of a calandria vault (CV) manipulator arm for use as a platform for inspection and repair of CV components.

Following Project 46552, a full release of 23,873k$ was approved in August 2006 as Project 46537, with an expected completion date of February, 2008. In order to meet the business objective to develop the capability to deliver a platform for inspection and repair end effectors to all of the specified calandria vault components, the following set of major deliverables were included:

- 2 CV manipulator arms, with the capability to deliver a platform for inspection and repair end effectors to all of the specified calandria vault components
- Ultrasonic and video inspection end effectors for the CV manipulator arms
- Mockups for tool testing and training
- Horizontal and vertical video on extension booms to provide overview visuals of the CV internals and for field of view cameras during the CV manipulator arm operations
- Non-arm tooling including: Robotic vehicle and associated video/ultrasonic end effectors, Ion Chamber Cooling Line inspection equipment
- Site preparations for unit inspections (station assessments and modifications were not included)
- Field testing of all inspection equipment in Unit 2 (schedule permitting)
- Training and procedures
- Project management and engineering

The targeted scope of work included the following components:

- Quantitative arm-based inspection of a subset of the 32 RTS waterbox support brackets in each unit, including the suspect 16 west RTS bracket in Unit 1, previously found to have an indication of a potential defect in the weld
- Quantitative arm-based inspection of a subset of cooling lines, including several hairpins and the two reactivity mechanism lines
- Quantitative inspection of all Ion Chamber Cooling Lines
- Qualitative (visual) inspection of a subset of hatch interspace lines
- Qualitative (visual) arm and non-arm based inspection of many calandria vault components

- Qualitative (visual) non-arm based inspection of the dump tank flexible supports

The capability to deliver a platform for inspection and repair end effectors to most (89%) or all of the specified calandria vault components is being addressed by this capital Project 46537.

Previous qualitative (visual) inspection of the CV cooling lines during P711 and confirmed during P941 showed significant corrosion and as a result, a no-touch inspection policy was decreed for any cooling lines in the absence of repair capability. Repair capability is currently beyond the scope of Project 46537.

Cost considerations, reduced accessibility, and the no-touch policy have necessitated a reduction in a proposed inspection scope of Unit 1 during P1011 to the following:

- Quantitative arm-based inspection of accessible RTS brackets through one of four CV penetrations, including the 16 west RTS bracket in Unit 1, previously found to have an indication of a potential defect in the weld
- Quantitative inspection of Ion Chamber Cooling Lines
- Qualitative (visual) arm and non-arm based inspection of biological shield cooling lines (hairpins, reactivity mechanism plug line, hatch interspace lines) and other calandria vault components

The present strategy is to inspect Unit 1 only. The scope of subsequent inspections would be dependent on inspection results from the Unit 1 inspections identified above.

The need to inspect the calandria vault components is driven by:

- OPG's desire to re-assure itself that the Calandria Vault components are not in danger of imminent failure, potentially resulting in serious process or structural failures in the Pickering A units.
- OPG's commitment to manage its nuclear fleet in a manner which enhances the confidence of employees, the public and regulatory authorities in the safety of its nuclear reactors.
- OPG's desire to make commercially sound decisions about future investments in Pickering A, by assuring itself of the condition and life expectancy of all of the major components in the units, prior to making significant on-going investments in other components

There are two compelling reasons for completing Project 46537 in time to allow inspections in the P1011 outage:

- Firstly, there is a pressing need to understand the condition of Pickering A calandria vaults, specifically the condition of the RTS waterbox support brackets. The RTS waterbox support brackets are considered to be irreparable. An inspection in the P1011 outage provides an opportunity to inspect a RTS bracket previously found in 1994 to have an indication of a potential defect in the weld, that may have the potential of growth in the calandria vault environment. Although the probability of failure is judged to be low, the significant consequence of RTS bracket failure is premature shutdown of a unit and possible process system upset due to the 3365 pound waterbox damaging other components in the vault. The significant consequence of RTS bracket failure is reflected in the Pickering A Site Management Board decision to ultrasonically inspect a limited number of RTS brackets from one penetration opening in the CV.
- Secondly, there is a lack of recent calandria vault condition information. If recent inspection data is gathered, further decisions can be made about the condition of the CV components thus resulting in possible mitigation of unexpected failures and/or non-sealable leaks of CV components.

This superseding request is driven by a major schedule variance caused by technical design issues that the robotic arm vendor has encountered. Additional funding is required to address this cost and scope variance.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Engineering has estimated that the probability of a non sealable coolant line leak remains above 20% for the remainder of Pickering A units 1 and 4 operating lifetime. In all of the alternatives below a non sealable coolant line leak is assumed to occur in 2014 (approximately mid way between now and end of life (EOL)). The resultant forced outage would have a duration composed of two distinct parts; preparation for inspection and repair, and the actual repair itself. The actual repair time is assumed consistent across all alternatives and is not included in this economic analysis. The time and cost for preparation is unique for each of the alternatives.

An assumed failure probability of 0.5% was confirmed by engineering for the risk of a RTS bracket failure between now and the EOL. It is assumed that a RTS bracket failure is irreparable and would require a permanent unit shutdown ahead of its EOL (The EOL for Pickering A units 1 and 4 is Q1 2020 for investment evaluation purposes).

Development of the capability to deliver a platform inspection and repair end effectors to most (89%) or all of the specified calandria vault components can reduce the forced outage duration. The reduction of forced outage revenue loss is compared against the project cost to acquire the inspection capability and possible repair tooling delivery, and comprises this economic assessment.

$000's	Base Case	Alt 1 Recommended		Alt 2 Do More	Alt 3 Do More
	No Arm Non-Arm Tools Completed	Full Cost Get Arm and Stop Non-Arm Tools Completed	Incr Cost Get Arm and Stop Non-Arm Tools Completed	Full vault coverage Non-Arm Tools Completed	Full vault coverage + Repair Non-Arm Tools Completed
Forced Outage Extension resulting from non sealable cooling line leak	(89,024)	(75,819)	(75,819)	(74,187)	(29,675)
Early EOL from RTS Bracket Failure	(15,943)	(15,943)	(15,943)	(15,943)	(15,943)
Total Revenue	(104,968)	(91,763)	(91,763)	(90,130)	(45,618)
Total OM&A	(1,270)	(1,270)	(1,270)	(1,270)	(1,270)
Capital Expenditures	(17,900)	(29,156)	(15,594)	(21,379)	(36,979)
Present Value (PV)	(67,012)	(72,419)	(60,834)	(64,694)	(53,997)
Net Present Value (NPV)	N/A	(5,407)	6,178	2,319	13,015
IRR%	N/A	N/A	25%	10%	17%
Discounted Payback (Yrs)	N/A	N/A	5.7	5.9	5.5

The sensitivity to the assumed probability of failure, and its assumed timing (2014) has been assessed for the Recommended Alternative.

Base Case: Not Recommended - Abandon Project, abandon arm contract, non-arm tools completed, no repair capability developed

The Do Nothing option (i.e. abandon arm contract, non-arm tools completed, no inspection and or repair capability developed) makes no attempt to finish developing the capability to deliver a platform for inspection and repair end effectors to most (89%) or all of the specified calandria vault components. There would be no "insurance policy" for inspecting or repairing a non-sealable leak should one occur. There would be no capability to perform an arm-based inspection of the specified calandria vault components in a future outage, such as the next planned Unit 1 outage in P1011. The impact of a non-sealable leak is a forced outage of 24 months to develop the capability to deliver a platform for inspection and repair end effectors and create repair tooling for a repairable failure or a permanent shutdown of the unit for an irreparable failure. The duration for repairs during a forced outage is not considered to be part of the 24 months.

The current plan in P1011 is to perform an arm-based inspection to attempt to assess the possibility of an irreparable RTS waterbox bracket failure in the calandria vault, which would require immediate shutdown of the unit with essentially no warning. If a failure of the bracket occurred, the waterbox may move, and may fall, which may damage other components in the vault such that the unit would be shut down permanently in advance of its normal EOL. The impact is a permanent shutdown of the unit for an irreparable failure.

The Do Nothing option subjects OPG to ongoing uncertainty in assessing the probability of calandria vault component failures between now and the EOL for Pickering A units 1 and 4.

The Do Nothing option subjects OPG to ongoing risk of not having the capability to deliver a platform for end effectors to inspect and repair certain components between now and the EOL for Pickering A units 1 and 4.

There is regulatory risk associated with the Do Nothing option as the CNSC has expressed an interest in the state of the Pickering A calandria vaults. While the overall risk to the public is judged to be acceptably low, certain failures could result in a serious process failure and the probability of serious process failures must be kept acceptably low as part of our licensing requirements. For example, failure of certain RTS brackets could lead to an RTS segment falling on moderator system piping inside the calandria vault resulting in a loss of moderator inventory accident.

There is reputational risk associated with the Do Nothing option. Should a CV component fail requiring a protracted outage to repair there could be negative public perceptions of OPG's ability to manage the nuclear fleet.

The Base Case Present Value (-67,012 k$), is composed of an assumed risk adjusted revenue loss from a non-sealable cooling line leak, assumed risk adjusted revenue loss from an RTS bracket failure, and assumed risk adjusted capital expenditure required to find and repair a non-sealable cooling line leak.

Alt. 1: Recommended - Completion of Project, 89% vault component accessibility, non-arm tools completed, no inspection execution training, no station preparations, no repair capability developed

This alternative includes the completion of this Project and will provide the capability to deliver a platform for inspection and repair end effectors to most (89%) of the specified calandria vault components. Due to very tight design margins, the calandria vault component accessibility scope will be limited to 89% of the specified components in the vault. The non-arm tools will be completed. Staff training and procedure preparation necessary to close this project will be prepared. Detailed staff training, procedures, and site preparation, required for first inspection use are covered under Project 46606 – Calandria Vault Inspection Execution.

The completed equipment capability with this alternative will provide OPG with an "insurance policy" for inspecting, but not repairing, a non-sealable leak should one occur. There will be the capability to perform an arm-based inspection of the specified calandria vault components in a future outage, such as the next planned Unit 1 outage in P1011. The impact of a non-sealable leak is a forced outage of 20 to 24 months, depending on accessibility, to create repair tooling for a repairable failure or a permanent shutdown of the unit for an irreparable failure. The duration for repairs during a forced outage is not considered to be part of the 20 to 24 months.

The current plan in P1011 is to perform an arm-based inspection to attempt to assess the possibility of an irreparable RTS waterbox bracket failure in the calandria vault, which would require immediate shutdown of the unit with essentially no warning. If a failure of the bracket occurred, the waterbox may move, and may fall, which may damage other components in the vault such that the unit would be shut down permanently in advance of its normal EOL. The impact is a permanent shutdown of the unit for an irreparable failure.

This alternative addresses the Do Nothing regulatory and reputation risks discussed in the base case. A reduction in forced outage duration is assumed once the development of the capability to deliver a platform for inspection and repair end effectors to most (89%) of the specified calandria vault components is completed.

To ascertain the failure probability at which a non sealable coolant leak in this alternative would break even, the failure probability within the financial model was reduced until the Net Present Value (NPV) of the alternative approached zero.

Failure probabilities in excess of approximately 6% ensured the NPV remained positive. The sensitivity to the assumed 2014 failure was also assessed. No matter when the assumed failure occurs during the period 2010 to EOL the resulting NPV from the financial model remains positive. However, near the EOL of the units, should there be a major failure, OPG would be unlikely to invest in major tooling to fix the failure unless there was a strong financial case to be made. An economic assessment would be made at that time.

Alt. 2: Not Recommended - Completion of Project, 100% vault component accessibility, non-arm tools completed, no inspection execution training, no station preparations, no repair capability developed

This alternative is similar to alternative 1 except that the vault component accessibility is increased from 89% to 100%.

This alternative includes the completion of this Project and will provide the capability to deliver a platform for inspection and repair end effectors to all of the specified calandria vault components. The non-arm tools will be completed. Staff training and procedure preparation necessary to close this project will be prepared. Detailed staff training, procedures, and site preparation, required for first inspection use are covered under Project 46606 – Calandria Vault Inspection Execution.

The completed equipment capability with this alternative will provide OPG with an "enhanced insurance policy" for inspecting, but not repairing, a non-sealable leak should one occur. There will be the capability to perform an arm-based inspection of the specified calandria vault components in a future outage, such as the next planned Unit 4 outage in P1141. Selecting this alternative may put the current plan for a P1011 inspection at risk since the arm may be required by the vendor to retrofit the enhanced accessibility capability. The impact of a non-sealable leak is a forced outage of 20 months to create repair tooling for a repairable failure or a permanent shutdown of the unit for an irreparable failure. The duration for repairs during a forced outage is not considered to be part of the 20 months.

The current plan in P1011 is to perform an arm-based inspection to attempt to assess the possibility of an irreparable RTS waterbox bracket failure in the calandria vault, which would require immediate shutdown of the unit with essentially no warning. If a failure of the bracket occurred, the waterbox may move, and may fall, which may damage other components in the vault such that the unit would be shut down permanently in advance of its normal EOL. The impact is a permanent shutdown of the unit for an irreparable failure.

This alternative addresses the Do Nothing regulatory and reputation risks discussed in the base case. A reduction in forced outage duration is assumed once the development of the capability to deliver a platform for inspection and repair end effectors to all of the specified calandria vault components is completed.

The estimated additional capital cost of 6.5 $M to achieve 100 % accessibility should be considered as conceptual quality (+60% to -25%).

Alt. 3: Not Recommended - Completion of Project, 100% vault component accessibility, non-arm tools completed, no inspection execution training, no station preparations, new Project started to develop full repair capability for a non-sealable leak of cooling lines

This alternative is similar to alternative 2 except that a new capital Project is started to develop full repair capability for a non-sealable leak of cooling lines.

This alternative includes the completion of this Project and will provide the capability to deliver a platform for inspection and repair end effectors to all of the specified calandria vault components. The non-arm tools will be completed. Staff training and procedure preparation necessary to close this project will be prepared. Detailed staff training, procedures, and site preparation, required for first inspection use are covered under Project 46606 – Calandria Vault Inspection Execution. A new Project will be started to develop full repair capability for a non-sealable leak of cooling lines.

The completed equipment capability with this alternative will provide OPG with a "very enhanced insurance policy" for inspecting and repairing a non-sealable leak should one occur. There will be the capability to perform an arm-based inspection of the specified calandria vault components in a future outage, such as the next planned Unit 4 outage in P1141. There will be the capability to perform an arm-based repair of a non-sealable cooling line leak in approximately 2012. Selecting this alternative may put the current plan for a P1011 inspection at risk since the arm may be required by the vendor to retrofit the enhanced accessibility capability. The impact of a non-sealable leak is a forced outage of approximately 8 months to prepare for deployment of the repair tooling for a repairable failure or a permanent shutdown of the unit for an irreparable failure. The duration for repairs during a forced outage is not considered to be part of the 8 months.

The current plan in P1011 is to perform an arm-based inspection to attempt to assess the possibility of an irreparable RTS waterbox bracket failure in the calandria vault, which would require immediate shutdown of the unit with essentially no warning. If a failure of the bracket occurred, the waterbox may move, and may fall, which may damage other components in the vault such that the unit would be shut down permanently in advance of its normal EOL. The impact is a permanent shutdown of the unit for an irreparable failure.

This alternative addresses the Do Nothing regulatory and reputation risks discussed in the base case. A significant reduction in forced outage duration is assumed once the development of the capability to deliver a platform for inspection and repair end effectors to all of the specified calandria vault components and with the capability to repair a non-sealable leak from cooling lines is completed.

The estimated additional capital costs of 6.5 $M to achieve 100 % accessibility and 19.5 $M to achieve repair capability should be considered as conceptual quality (+60% to -25%).

This alternative is not being recommended because of the significant schedule risk performing this alternative would add to the preparations for the P1011 inspection. Also, it is desired that prior to committing additional funding to perform this alternative, inspection data be gathered as early as possible to enable the preparation of an assessment on vault equipment conditions.

The incremental NPV for this alternative, in comparison to the recommended, is eroded, but remains positive, if the costs to achieve 100% accessibility and repair capability are at the high end of the conceptual quality estimate. If this were to occur, the recommended alternative provides better economic benefit.

Alt 4:

Alt. 5:

4/ THE PROPOSAL

We recommend an additional release of **2,524k$** (including 1,091k$ contingency) to complete the deliverables for the Calandria Vault Inspection Project, bringing the total release of funds to 26,397k$.

This proposal involves the completion of this Project and will provide the capability to deliver a platform for inspection and repair end effectors to most (89%) of the specified calandria vault components. Due to very tight design margins, the calandria vault component accessibility scope will be limited to 89% of the specified components in the vault. The non-arm tools will be completed. There will be minimal training and procedures. The majority of training and procedures will be covered by a separate Project 46606 – Calandria Vault Inspection Execution. No further station preparations will be performed. Any further station preparations will be covered by a separate Project 46606 – Calandria Vault Inspection Execution.

Repair capability is outside the scope of Project.

The execution of an inspection is outside the scope of this Project and is being addressed by Project 46606 – Calandria Vault Inspection Execution.

The recommended alternative attempts to balance the risk of not being ready to repair an unexpected failure in a Calandria Vault component with the potential of spending too much up-front, only to find that conditions are better (i.e. no need for repairs) or worse (i.e. irreparable flaws) than expected. Repairable failures include most cooling water lines, RTS segment vent lines, helium line anchors, and ion chamber cooling lines. Failure of an RTS bracket resulting in displacement of the RTS waterbox segment is considered irreparable.

The deliverables for this proposal include:

- 2 CV manipulator arms, with the capability to deliver a platform for inspection and repair end effectors to most (89%) of the specified calandria vault components – **In Progress**
- Ultrasonic and video inspection end effectors for the CV manipulator arms – **In Progress**
- Mockups for tool testing and training – **Completed**
- Horizontal and vertical video on extension booms to provide overview visuals of the CV internals and for field of view cameras during the CV manipulator arm operations – **In Progress**
- Non-arm tooling including: Robotic vehicle and associated video end effectors, Ion Chamber Cooling Line inspection equipment – **In Progress**
- Minimal training and procedures – **In Progress**
- Shipping and storage containers for the equipment developed in this Project – **In Progress**
- Project management and engineering – **In Progress**

This proposal does not include funding for repair capability or repair end effectors.

5/ QUALITATIVE FACTORS

Pickering A Life Cycle Planning

Proceeding with the recommended alternative will allow the Project to complete the development of the capability to reach and deliver inspection and repair end effectors to most (89%) of the specified calandria vault components at Pickering A units 1 and 4. The tools could be used to perform inspections, repair activities, and identification of all non-sealable leak locations. The equipment developed can be used to provide a general assessment on vault conditions and provide quantitative inspection data of a subset of the calandria vault components, specifically the RTS waterbox support brackets and carbon steel cooling lines. This information will allow OPG to better understand the risk of premature shutdown of the Pickering A units. It is expected that periodic inspections may be performed in the future for degradation rate determination and funded through OM&A.

Benefits to Public/Regulator Relations

Proceeding with the recommended alternative will allow OPG to address the risk of potential significant failures of calandria vault components. Proactive inspection and failure risk assessment of the critical components would avert the significant negative consequences on OPG's public image that would arise from a permanent shutdown of the unit from an irreparable RTS waterbox bracket failure or a forced outage from a non-sealable leak of a cooling line.

Future inspection and condition assessment of critical CV components would prove beneficial from a regulatory perspective, as the CNSC has recently expressed interest in the condition of the Pickering A calandria vaults.

6/ RISKS (see Attachment E for details)

Low = 1 to 3 | Medium = 4 to 9 | High = 10 to 25

		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Probability x Impact									After Mitigation: Probability x Impact								
		Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Quality: A robotic arm deficiency is discovered after acceptance by OPG	Maximize scope of factory and full scale mockup acceptance tests Timely vendor support available for part replacement and maintenance/training support A significant portion of the inspection/repair platform developed will be exercised under Project 46606 – Calandria Vault Inspection Execution, confirming its suitability for future inspection and/or repair campaigns.	8	16	20					16	**20**	4	12	12					4	**12**
Quality / Cost: Equipment changes required after receipt and prior to in-service declaration, not part of current requirements or warranty claims.	Maximize scope of factory and full scale mockup acceptance tests Test/commission with end effectors to identify potential deficiencies A significant portion of the inspection/repair platform developed will be exercised under Project 46606 – Calandria Vault Inspection Execution, confirming its suitability for future inspection and/or repair campaigns Include funding in this superseding business case summary to make minor changes.	2	4	12	-	-	-	-	-	**12**	2	4	4	-	-	-	-	-	**4**
Schedule / Cost: Significant delays in delivery of the inspection equipment, including the remote manipulator arm, such that estimate to complete Project is too low.	Include contingency in this superseding business case summary to address this risk.	6	10	-	-	-	-	-	-	**10**	6	8	-	-	-	-	-	-	**8**

		Low = 1 to 3	Medium = 4 to 9		High = 10 to 25	
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Probability x Impact									After Mitigation: Probability x Impact								
		Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Schedule / Cost: Scope additions not originally considered such as the need to categorize the control software provided with the robotic arm to a more strict standard (CAT III) than is being provided currently (CAT IV)	Prove software is appropriately categorized as CAT IV. There is a contingency amount identified to address the risk of the software being categorized as CAT III.	3	15	6					15	**15**	3	6	6					3	**6**
Schedule / Cost: Vendor work stoppage as a result of labour disruption or financial claim(s).	Once it occurs, negotiate a resolution of labour or financial claim(s) with vendor This risk is not funded by this release	8	20	-	4	-	-	-	-	**20**	12	12	-	4	-	-	-	-	**12**
Technical: Inspection equipment unable to provide desired results because of material surface condition or other factors	Performance test of surface prep, ultrasonic, and visual equipment on prepared surfaces simulating anticipated surface conditions Test/commission with end effectors in simulated full scale mockup environment to identify deficiencies A significant portion of the inspection/repair platform developed will be exercised under Project 46606 – Calandria Vault Inspection Execution, confirming its suitability for future inspection and/or repair campaigns	12	15	15						**15**	3	15	9						**15**
Technical: Inspection equipment fails to meet design requirements and cannot be accepted from the vendor.	Do not accept inspection equipment and default vendor, if no other resolution can be reached.	15	15	15	9	6	-	-	-	**15**	15	15	15	9	6	-	-	-	**15**
Technical: Arm's 89% reach capability means there are a minimum number of targets which cannot be accessed for quantitative (ultrasonic) inspection or repair.	If required, select alternative to fund vendor to provide 100% reach capability The 11% impairment may be recoverable through the use of custom end effectors for the manipulator arm, however, this scope has not been included in this Project.	8	15	4	-	4	-	-	-	**15**	8	15	4	-	4	-	-	-	**15**

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
	Impact				
Probability	1	2	3	4	5
5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Technical: Arm end effectors not built by the arm manufacturer may have integration issues	The manufacturers for end effectors were provided with the necessary interface information during their design process. The Project requested that prototype tooling be developed and tested in the mockups prior to finalizing the design. Integration testing is being performed in the full scale mockup prior to deployment in the field. Include contingency in this superseding business case summary to address this risk.	3	12	12						**12**	3	6	3						**6**
Environmental: No significant environmental risks associated with this Project.																			
Investment: Arm vendor does not fulfill contractual obligations and is in a position of default. Arm portion of Project is cancelled resulting in a write-off to OM&A of 7,573k$.	If this occurs, work with vendor to negotiate another amendment to the contract to avoid complete default. Contract default provisions are in the contract.	6	15							**15**	3	12							**12**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Comprehensive	Apr 2011	Sep 2012	Director – Station Engineering Pickering A

- An independent Comprehensive Post Implementation Review (CPIR) will be conducted, consistent with the corporate PIR procedure
- The CPIR will be an independent and systematic performance evaluation of the project against these objectives:
  - Assess the realization of the project benefits
  - Review project intent, plan, implementation and operational performance
  - Review BCS – major assumptions, economic and financial evaluation look back from results, for future decisions
  - Review project risk management
  - Identify lessons learned
- Lessons learned on the technology development, contracting strategy, and planning will be captured in addition to the project execution lessons

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	All partial AFS declarations of non-arm equipment completed	Several partial AFS declarations completed to date	All partial AFS declarations completed	AFS declaration forms for non-arm equipment	IM&CS Project Team
2.	Acceptance test of manipulator arms and equipment against OPG design requirements	Acceptance test not started	All acceptance test results accepted or dispositioned	Vendor report – Line Item Verification Completion Notice (LIVCN) accepted by OPG	IM&CS Project Team
3.	Partial AFS declaration of manipulator arms and equipment	Partial AFS declaration not started	Partial AFS declaration completed	AFS declaration form for arm equipment	IM&CS Project Team
4.	Final AFS declaration for all equipment	Final AFS declaration not started	Final AFS declaration competed	Final AFS declaration form for all equipment	IM&CS Project Team
5.	6 out 6 financial in-service declarations for Project completed	2 out of 6 in-service financial declarations completed to date	6 out of 6 in-service financial declarations completed	Financial in-service declaration forms	IM&CS Project Team

Appendix "A" Glossary (acronyms, codes, technical terms)

AFS	Available For Service
CNSC	Canadian Nuclear Safety Commission
COMS	Constructability, Operability, Maintainability, and Safety
CPIR	Comprehensive Post Implementation Review
CV	Calandria Vault
CVI	Calandria Vault Inspection
DA	Design Authority
EC	Engineering Change
EOL	End of Life
IM&CS	Inspection, Maintenance and Commercial Services
IRR	Internal Rate of Return
ISD	In Service Declaration (Also known as REIS)
KWH	Kilowatt Hours
LIVCN	Line Item Verification Completion Notice
LTD	Life to Date
NDE	Non Destructive Examination
NPV	Net Present Value
OEB	Ontario Energy Board
OM&A	Operating, Maintenance and Administration
OPG	Ontario Power Generation
OPGN	Ontario Power Generation, Nuclear
P711	The first planned outage in 2007 in Pickering A Unit 1
P941	The first planned outage in 2009 in Pickering A Unit 4
P1011	The first planned outage in 2010 in Pickering A Unit 1
PEP	Project Execution Plan
PIR	Post Implementation Review
REIS	Report of Equipment In Service (Also known as ISD)
RTS	Ring Thermal Shield
UT	Ultrasonic – one method of NDE
YTD	Year To Date

CAT III	Category III is assigned to software that, while important, can be implemented with a less rigorous design process than Category I or II software. This could be software where the failure has a less direct impact on risk or where the impact is on a system of lower significance.
CAT IV	Category IV is assigned to software where a *software failure* has no nuclear safety impact and impacts on risks identified in the risk-based ECC are very limited. While the Category IV software design process can be less rigorous than that of Category III software, a systematic design process should still be used.

Appendix "B" **Project Funding History**

$ 000's Release Type	Month	All Existing and Planned Releases (incl contingency) Cumulative Values Year	2005	2006	2007	2008	2009	2010	2011	Later	Total
Developmental	Aug	2005	232	449							681
Full	Aug	2006	1,806	8,994	3,776	7,324	1,973				23,873
Superseding	Jun	2009	1,806	8,994	3,776	7,868	3,841	112			26,397
											0
											0
											0
											0
											0
LTD Spent	Mar	2009				16,698					16,698

Comments:

Previously, approximately 660k$ was spent on Project Scoping using funding from the Pickering A Return to Service budget.

Subsequently, Project 46552 was initiated (developmental release) in 2005 with the major deliverables being two vendor proposals for the design and fabrication of a calandria vault (CV) manipulator arm for use as a platform for inspection and repair of CV components.

Following Project 46552, a full release of 23,873k$ was approved in August 2006 as Project 46537, with an expected completion date of February, 2008. In order to meet the business objective to develop the capability to deliver a platform for inspection and repair end effectors to all of the specified calandria vault components, the following set of major deliverables were included:

- 2 CV manipulator arms, with the capability to deliver a platform for inspection and repair end effectors to all of the specified calandria vault components
- Ultrasonic and video inspection end effectors for the CV manipulator arms
- Mockups for tool testing and training
- Horizontal and vertical video on extension booms to provide overview visuals of the CV internals and for field of view cameras during the CV manipulator arm operations
- Non-arm tooling including: Robotic vehicle and associated video/ultrasonic end effectors, Ion Chamber Cooling Line inspection equipment
- Site preparations for unit inspections (station assessments and modifications were not included)
- Field testing of all inspection equipment in Unit 2 (schedule permitting)
- Training and procedures
- Project management and engineering

This release did not include funding for repair capability or repair end effectors.

Appendix "C" Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	3%	SR & D Opportunity	Yes
Progress Payments	Yes	Foreign Currency	N/A	Retainer Fee	
Income Tax Rate	Generation	PST		Interest Rate (Capital)	6%
Depreciation Rate (Capital)	Generating Equipment 8%	Leasing		Indexed Priced Contract	No

Comments:

Project Cost Estimate:

Design Complete	100%	Quality of Estimate	Release + 15% to - 10%	3rd Party Estimate	No
Reviewed by Sponsor	Yes	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	Nothing Similar	Budgetary Quote(s)	N/A	First Unit Actual Used	No
Cost Sharing	No	Contracts in place	All in place	Competitive Bid	Yes
Fixed Price Contract	Yes	Fee for Service	Yes	Firm Vendor Proposal	Yes

Comments:

Alternative	Forced Outage (Months) [Leak is Accessible]	Forced Outage (Months) [Leak is Not Accessible]	Probability leak is accessible	Inspection Cost if Leak is accessible ($M) [without 30% premium]	Inspection Cost if Leak is Not Accessible ($M) [without 30% premium]	Repair Cost ($M) [without 30% premium]
Base Case	24	24	0.00	N/A	25	15
Alt 1 (Recommended)	20	24	0.89	0	25	15
Alt 2	20	24	1.00	0	N/A	15
Alt 3	8	24	1.00	0	N/A	N/A

The duration for repairs during a forced outage is not considered to be part of the Forced Outage Months in the table.

Rationale for Cost Classification:

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)						
Pickering A	1	Mar	2020	513	85%	P1011						
	4	Mar	2020									
Pickering B	5											
	6											
	7											
	8											
Darlington	1											
	2											
	3											
	4											

Comments:

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Impact on Revenue

$000's	Present	2010	2011	2012	2013	2014	2015	2016	Later	Total
Rate KWH										
Probability										0.0%
Consequence										0
Risk						(46,600)	(46,600)	(2,721)	(9,048)	(104,968)
Other										0
Base Case	0	0	0	0	0	(46,600)	(46,600)	(2,721)	(9,048)	(104,968)
Probability										0.0%
Consequence										0
Risk						(77,907)	(2,088)	(2,721)	(9,048)	(91,763)
Other										0
Recommendation	0	0	0	0	0	(77,907)	(2,088)	(2,721)	(9,048)	(91,763)
Net Impact	0	0	0	0	0	(31,307)	44,512	0	0	13,205

Comments:

FIN-TMP-PA-006, Revision R01 BCS Template is utilized for all PNGSA NPV calculations
The Template assumptions are used as is and are contained in the spreadsheet titled "Assumptions_Using Sheet"
For a non-sealable leak, it is assumed that the forced outage occurs in 2014, unless otherwise stated
The probabilities of failure for each case are as shown
It is assumed that if a non-sealable leak occurs, it is for one unit only, however, the repair capability would be applicable for both Unit 1 and Unit 4
It is assumed that the actual outage costs to perform a non-sealable leak repair are not included as these are assumed to be the same for all alternatives
It is assumed that if a forced outage occurs from a non-sealable leak, all OM&A and capital costs estimates will be escalated by a 30% premium to expedite material and labour
For a bracket failure, it is assumed that the failure occurs in 2014, unless otherwise stated
It is assumed that the Unit 1 and Unit 4 EOL is Q1 2020 for investment evaluation purposes.
It is assumed for the CVI options without repair capability that the repair capability Project and station assessments and modifications are carried out during the non-sealable leak forced outage
It is assumed that all CVI Project committed costs are sunk costs and not included in the various NPV calculations, except for the Alt 1 - Full Cost alternative
For the purpose of NPV calculations, it is assumed that the cost to develop inspection capability is $25M over the 24 month period
For the purpose of NPV calculations, it is assumed that the cost to develop repair capability is $15M over the 20 month period
LTD at Dec 31, 2008 is $14,576
Mar 31, 2009 YTD is $2,122
Project committed costs of $7.5M, used in Base Case
Additional Capital Cost to achieve 100 % accessibility is 6.5 $M, used in Alternative 2 and 3
Additional Capital Cost to achieve repair capability is 19.5 $M, used in Alternative 3

Impact on OM&A

$000's	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A										0
Outage OM&A			(750)							(750)
Project OM&A							(520)			(520)
Base Case	0	0	(750)	0	0	0	(520)	0	0	(1,270)
Base OM&A										0
Outage OM&A			(750)							(750)
Project OM&A							(520)			(520)
Recommendation	0	0	(750)	0	0	0	(520)	0	0	(1,270)
Net Impact	0	0	0	0	0	0	0	0	0	0

Comments:

All NPV calculations include P1011 non-arm inspection cost included at $750K

All NPV calculations exclude station assessments and modifications costs, unless they occur in 2014

It is assumed that the station assessments and modification costs in 2014 are as follows: $2.0M x 1.3 x probability of cooling line leak

All NPV calculations exclude arm training costs to be covered under Project 46606 – Calandria Vault Inspection Execution

All NPV calculations exclude arm station preps and equipment costs to be covered under Project 46606 – Calandria Vault Inspection Execution

All NPV calculations exclude arm inspection costs to be covered under Project 46606 – Calandria Vault Inspection Execution

Calandria Vault Inspections 13 - 46537

Superseding Business Case N - BCS - 30673 - 10001 – R00

Attachment "A" **Project Cost Summary**

	$000's Capital	LTD 2008	YTD Mar2009	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnt & Engineering	2,245	243	697	578	62					3,825
	Permanent Materials	10,877	1,612	4,056	1,714	-					18,259
	Testing/Commissioning	195	61	345	175	-					776
	Training	121	79	219	-	-					419
	Expenses	124	5	31	11	-					171
											-
											-
											-
											-
	Interest (Capital Project Only)	1,014	122	398	272	50					1,856
	Project Costs	**14,576**	**2,122**	**5,746**	**2,750**	**112**	**-**	**-**	**-**	**-**	**25,306**
	General Contingency	-			1,091	-					1,091
	Specific Contingency	-			-	-					-
	Project Costs	**14,576**	**2,122**	**5,746**	**3,841**	**112**	**-**	**-**	**-**	**-**	**26,397**
Cash	**Adjust to Cash Basis + / -**									-	-
	Project Costs	**14,576**	**2,122**	**5,746**	**3,841**	**112**	**-**	**-**	**-**	**-**	**26,397**
Funding	**Currently Released**	14,576	7324		1,973						23,873
	This Release	-	544		1,868	112					2,524
	Future Release	-	0		-	-				-	-
	Project Funding	**14,576**	**7868**		**3,841**	**112**	**-**	**-**	**-**	**-**	**26,397**

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

		LTD 2008	YTD Mar2009	2009	2010	2011	2012	2013	2014	Later	Total
Budget	2009-2013 Business Plan	13,200	8700		1,900						23,800
	Variance to Business Plan	**1,376**	**-832**		**850**	**112**	**-**	**-**	**-**	**-**	**1,506**
Other	**Removal Costs included above**										-
	Inventory to be written off										-
	Spare Parts in Inventory										-

The estimated variance(s) to the **2010-2014 Business Plan** will be addressed through the portfolio management process.
A PCRAF **was approved in** Jan 2009.

Reviewed By:
Marc Paiment Marc Paiment 15July2009
Name
Project Manager
Date:

Approved By:
DON JARRELL 15JULY 2009
Name
Strat IV Manager
Date:

Calandria Vault Inspections 13 - 46537

Superseding Business Case N - BCS - 30673 - 10001 – R00

Attachment "B" **Project Variance Analysis**

	Capital	LTD Mar 2009	Total Project Last BCS Aug 2006	Total Project This BCS Jun 2009	Variance	Comments
Scores Basis	Project Mgmnt & Engineering	2488	4495	3825	-670	(See Note 1)
	Permanent Materials	12489	13550	18259	4709	(See Note 2)
	Testing/Commissioning	256	459	776	317	(See Note 3)
	Training	200	658	419	-239	(See Note 4)
	Expenses	129	580	171	-409	(See Note 5)
					0	
					0	
					0	
					0	
	Interest (Capital Project Only)	1136	1127	1856	729	(See Note 6)
	Project Costs (Scores Basis)	**16698**	**20869**	**25306**	**4437**	
	General Contingency		**3004**	**1091**	-1913	(See Note 7)
	Specific Contingency				0	
	Project Costs (Scores Basis)	**16698**	**23873**	**26397**	**2524**	

Other	**Removal Costs included above**				0	
	Inventory to be written off				0	
	Spare Parts in Inventory				0	

Comments:
Cost, schedule, and scope variances have occurred on this Project, resulting in a cost impact of **+7091k$**. However, through value engineering, the application of Project controls, and minimization of resources and expenses, the overall impact is **+2524k$**. The need for changes to the Scores Basis from the full release BCS to this superseding request are as follows:

NOTES:

1.
a) Delayed addition of resources on Project to accommodate delays
b) Redeployed existing resources on Project to accommodate delays

2.
a) Underestimated cost for the CV mockup for tool testing and training, impact **+1000$k**
b) Robotic arm costs increased over estimate due to delays and overspend by vendor resulting in an amendment to increase the firm fixed price contract, impact **+1700$k**

Background:

- Robotic arm vendor design difficulties resulting in major cost overruns and schedule delays on the firm fixed price contract. The design difficulties at the vendor were due to the design constraints of this Project such as: a) the extremely long reach required; b) the small cross-section of the penetration into the CV; c) the initial schedule for delivery; and d) vendor program management errors such as: i) sub-contracting the robotic arm to attempt to meet schedule demands; ii) following an internal non-standard process such as not building a prototype system first, then the final system; and iii) following an internal non-standard process such as inadequate oversight during the design process and reviews

- Robotic arm vendor quality difficulties resulting in major cost overruns and schedule delays on the firm fixed price contract. The quality difficulties were as follows: i) design errors; ii) inadequate design margins; iii) lack of quality control and receipt inspection; and iv) infrequent sub-contractor oversight

c) Robotic arm costs increased, impact **+1200k$**, due to:
 i) scope increases to vendor to address clarified design requirements
 ii) address new design requirements required as part of discovery work during Project
 iii) perform assessments of impact of discovery work

d) Added scope not originally considered such as an engineered tool to insert and remove station CV penetration shield plugs, impact **+200k$**

e) Added scope not originally considered such as the need to modify the end effectors and/or the robotic arm after receipt to ensure their effectiveness for use, impact **+900k$**

3. Performance of risk mitigation measures, not originally in scope, such as field measurements and vault field-run component configuration awareness and verification during the P711 outage, impact **+300k$**

4. Reduced training on robotic arm portion of Project

5. Minimized expenses on entire Project throughout life cycle through reducing scope where possible and applying value engineering

6. Underestimated interest costs due to delays on robotic arm contract resulting in delays of issuing of a report of equipment in service, impact **+700k$**

7. Used all of 3004k$, residual risk left is **+1091k$** based on current list of risks

Attachment "C" **Milestones and In Service Declarations**

Key Milestones

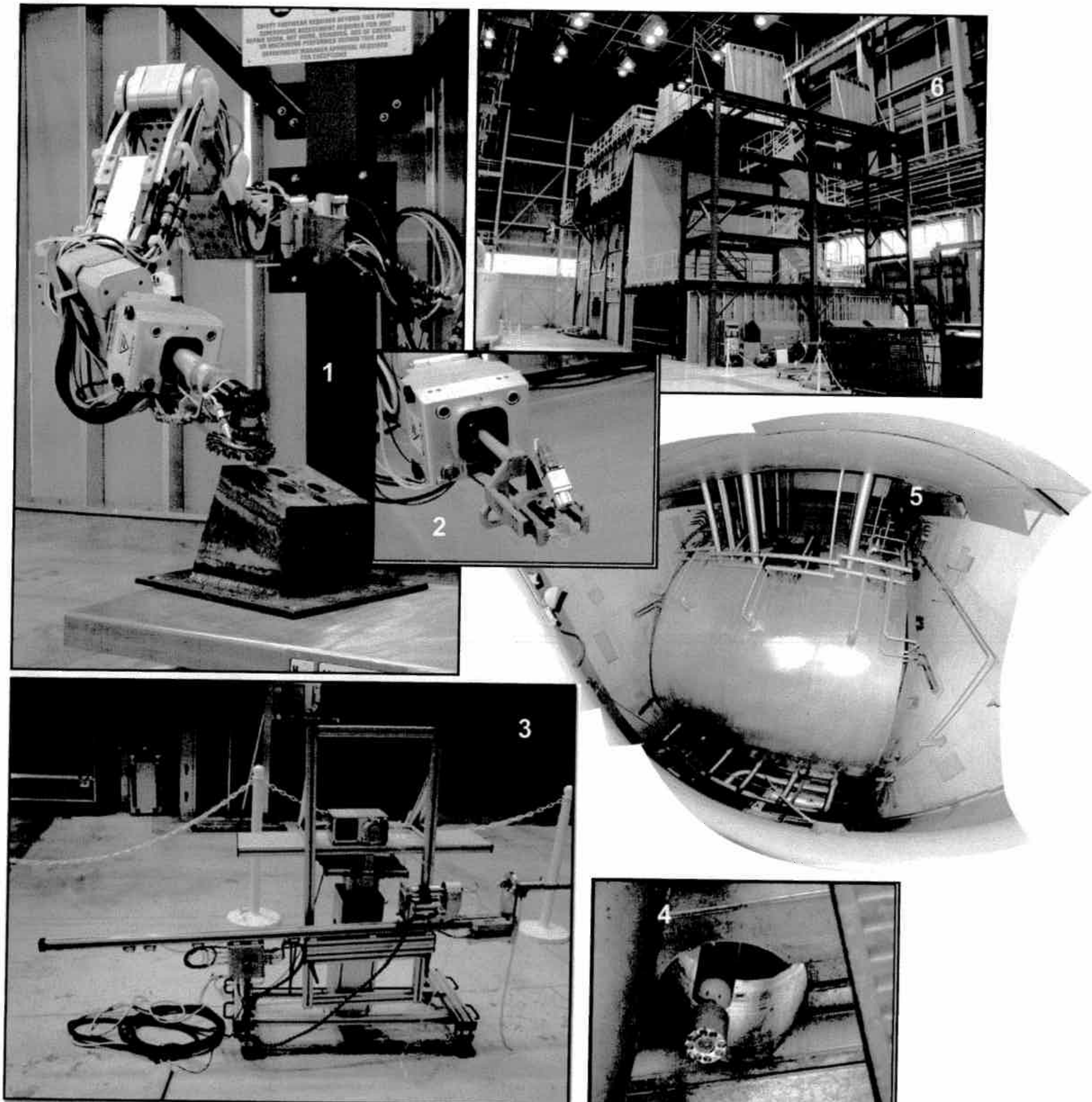
Completion Date			Description
Day	Mth	Yr	
	May	2006	Winning bid selected – **Completed** May 2006
	Jul	2006	PO issued to vendor – **Completed** Nov. 2006
	Dec	2006	Final Design of Manipulator arm complete – **Completed** May 2007
	Jan - Apr	2007	Field trial of non-arm inspection equipment in Unit 2 – **Completed** Nov. 2007 in P711
	Sep	2007	Delivery of first CV manipulator arm – Scheduled for Jan. 2010
	Nov	2007	Delivery of second CV manipulator arm – Scheduled for Mar. 2010
	Feb	2008	Field trial of CV manipulator arm in Unit 2 and in service declaration – Field trial in Unit 2 cancelled, trial will be in full scale mockup, in service declaration scheduled for Apr. 2010
	Mar	2008	Inspection of Unit 4 – **Completed** non-arm inspection Jan. 2009 in P941, Unit 4 arm inspection not scheduled
	Sep	2008	Inspection of Unit 1 – Arm inspection scheduled for Jun. 2010 in P1011
29	Jan	2010	1 CV manipulator arm takeover
6	Mar	2010	1 CV manipulator arm takeover
15	Apr	2010	AFS for equipment
6	Apr	2011	Project Closeout

A revised Project Execution Plan (PEP) **will be approved by Oct 2009**

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%
April	2008	ISD #1 Calandria Vault Full Scale Mockup - **Completed**	2,059	8.1
April	2009	ISD #2 Non-Arm, Non-ICCL Support and Inspection Equipment - **Completed**	2,607	10.3
Aug.	2009	ISD #3 ICCL Inspection Equipment	584	2.3
Oct.	2009	ISD #4 Manipulator Arm Ultrasonic End Effectors	910	3.6
April	2010	ISD #5 Manipulator Arm	17,335	68.5
April	2011	ISD #6 Project Closeout	1,811	7.2

Attachment "D" **Project Pictures**



Picture #1: 6 degree of freedom robotic manipulator arm with surface preparation end effector attached; #2: Close-up of ultrasonic end effector integrated with robotic arm; #3: Ion Chamber Cooling Line inspection system during testing & commissioning; #4: Vertical Overview Camera during testing & commissioning; #5: Panoramic view of inside of calandria vault mockup; #6: Calandria vault mockup and platforms.

Internal OPG Website: http://cmsprod.corp.opg.com/OPG/Content/Nuclear/IMS/About/Projects+-+46537.htm

Attachment "E"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 months)	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges **OR** Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages **OR** Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to Project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety relat[illegible] s[illegible]
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of G[illegible]	[illegible]

PNGS-A PHT D2O Storage Tank Project (U2/3 SS Project) 13 - 46576

Superseding Business Case NA44 - BCS - 38000 - 00002 – R004

1/ RECOMMENDATION:

We recommend an additional superseding release of $1,871k (including $300k contingency) to complete the remaining installation and commissioning of D_2O storage tanks in the Upgrading Processing Plant (UPP) building. Total release requested is $16,327k (including $300k contingency).

The business objectives of this project are:

- To provide permanent storage for approximately 240 mega grams (Mg) of low curie D2O to be drained from the Pickering Units 2 and 3 Primary Heat Transport (PHT) systems during the Safe Storage (SS) Project.
- Provide additional D2O Storage and Inventory (S&I) capacity at the Pickering site, to improve accessibility, continuity and dependability of high isotopic, low curie heavy water supply.

The project was fully released in March 2007 with an estimated cost of $11,171k. Major cost variances necessitating a February 2009 superseding BCS. The increases necessitating the Feb 2009 Superseding BCS ($14,45k including $749k contingency) were attributed to:

- Cost and schedules delays resulting from the original contractor's inability to effectively implement an asbestos abatement program required as part of demolition activities.
- Legacy configuration management issues delayed the demolition planning and assessing work scope. In addition, extensive on-line wiring updates were required prior to system removal.
- Increased design costs resulting from poor Design Agency performance and the inability of OPG to provide timely reviews of Design Agency documentation due to conflicting project priorities.
- Costs associated with the non-standard size of the micro pile casing specified by the Design Agency as well as underestimating the quantity of grout material required for 24 micro piles and six test piles.

At the time the February superseding BCS was prepared, the poor quality of the design Engineering Changes (ECs) and resulting 6 month project schedule delay was not anticipated as a risk. More specifically, approximately 200 Field Changes were processed subsequent to the February superseding BCS submittal. These field changes, primarily due to the poor quality of the design packages received from the Design Agency, affected 6 design ECs and required 20 design EC revisions to incorporate the field changes necessitating re-work in the field. As project costs continued to escalate the project did not adequately track or forecast these project costs to completion. The project monitored actual costs through SCORES reports and used the contractor's cost reports to track the forecast costs to complete without adequate independent verification. In summary, increased cost variances related to the outstanding work remaining under the February 2009 BCS has necessitated this additional superseding BCS release. The requirement for additional funds are attributed to:

- Scope changes due to inaccurate and/or incomplete design packages prepared by third party Design Agency.
- Increased contractor indirect costs (project management) due to schedule delays (6 months).
- Underestimating installation costs related to original scope of work.

The cumulative affect of the issues identified above delayed the Partial Available For Service (AFS) date to October 14/09 (when the storage tanks were made available for service to receive heat transport water). Unit 3 critical path drain activities were re-sequenced to ensure the Safe Storage project was not adversely affected by the schedule delay. Consequently, the additional storage capacity made it possible to transfer 150 Mg of the estimated 235 Mg of low curie heavy water from S&I storage to UPP-A, releasing sufficient storage capacity within S&I to support the Unit 6 moderator drain planned during the P961 outage at the end of October. The remaining field work includes the installation of the interior and exterior stairwells and this work is scheduled to be completed by end of December.

The revised estimate to completion includes approx. 15% contingency allowance on the remaining work, re-estimated by the contract vendors September 10, 2009. Mitigating actions have since been implemented to establish scope control measures and Construction Manager screening process to better monitor and control cost extras as a result of field initiated changes. In conclusion, significant project risk has been retired since the superseding BCS in February 2009.

BUSINESS CASE SUMMARY

$000's (incl contingency)	Type	LTD 2008	2009	2010	2011	2012	2013	Later	Total
Currently Released	Superseding	8,367	6,089						**14,456**
Requested Now	Superseding		1,082	789					**1,871**
Future Funding Req'd	None								**-**
Total Project Costs		**8,367**	**7,171**	**789**	**-**	**-**	**-**	**-**	**16,327**
Non Project Costs									**-**
Grand Total		**8,367**	**7,171**	**789**	**-**	**-**	**-**	**-**	**16,327**

Investment Type	Class	NPV	IRR	Discounted Payback
Sustaining	Capital	12,408	NA	NA

Submitted By:

Nov 23/09

Mark Elliott Date:
Senior Vice President, Pickering A

Finance Approval:

RH Nov 24/09

Donn Hanbidge Date:
Chief Financial Officer

Line Approval (Per OAR Element 1.4 Variance):

26 Nov 09

Tom Mitchell Date:
President and Chief Executive Officer

2/ BACKGROUND & ISSUES

A requirement of the Pickering Unit 2 and 3 Safe Storage project scope of work includes dewatering the two reactors to place them in a safe state as a pre-requisite for final decommissioning. The storage capacity required to drain Unit 2 and Unit 3 PHT D_2O is estimated to be 240 Mg. The original plan to store the D_2O in each Unit's underground spent resin storage tank was rejected by the Safe Storage Project management challenge process. This necessitated investigating other alternative solutions.

The Safe Storage project confirmed four 100 Mg stainless steel D_2O storage tanks were available at the decommissioned Bruce Heavy Water Plant. The tanks provided sufficient capacity to address Safe Storage dewatering requirements as well as providing enhanced storage capability for the station. The option of using drums for permanent D_2O storage is currently not a desirable option. Drums should only be used as a temporary and contingency measure when more permanent storage is not available.

The installation of 400 Mg of additional low curie D_2O storage capacity addresses fully or in part the following station problems:

1. The lack of acceptable storage capacity for Unit 2 and 3 PHT D_2O may extend the Unit 2 and 3 Safe Storage Project significantly increasing Safe Storage project costs, estimated at $3M/month of delay.
2. Storing low Curie heavy water in permanent storage tanks instead of off-site & on-site drum storage will provide the Pickering station greater flexibility managing its D_2O inventories to support continuous station operations in a safe and cost-effective manner. The additional storage capacity will provide 240 Mg of low Curie D_2O, of which 120 Mg is reactor grade D_2O that can be immediately used to perform bulk D_2O transfers and make improvements in D_2O Curie concentrations and isotopics of operating units. This is especially important for those units close to or exceeding their Administrative limits for tritium concentrations in Moderator systems and approaching the regulatory limits prescribed in the Operating Policies & Procedures (25 Ci/kg for moderator D_2O and 2.5 Ci/kg for HTS D_2O). Furthermore, the proximity of the proposed storage tanks to the heavy water upgrader simplifies operator interfaces since new annunciation and control will be installed within the existing UPP control room. Additional storage capacity will also facilitate processing the low curie D_2O to and from the UPP-B upgrader system without having to rely on S&I tank availability.

It should also be noted that since the initial full release BCS was approved (Mar. 26, 2007):

- The Darlington S&I project (31555) was deferred until after the Refurbishment decision.
- The PNGS-A D_2O Storage and Drum Cleaning Facility project (49521) was deferred.

Consequently, there are no other storage and inventory upgrade projects planned in the near future to deliver additional heavy water storage capacity thus re-enforcing the importance to complete the UPP Storage Project, giving OPG D_2O Management greater flexibility managing heavy water inventories while reducing drum handling and storage requirements and associated costs.

The cost variances incurred by the project can be attributed to the following circumstances, which were identified as project risks at the onset but were not managed with sufficient rigor to fully mitigate their consequences and minimize their impact on the project.

- A decision was made to contract the demolition phase of the project, on a fixed price basis, with a General Services Agreement (GSA) Contractor that was relatively inexperienced working larger size projects at PNGS. At that time, the SS Project management accepted this risk considering the potential benefit of developing a second contractor and competition for PNGS construction contracts. This contract was ultimately terminated due to schedule and cost over runs and the alternate contractor was employed to complete the demolition work. The project was delayed nine months as a result of the demolition challenges.
- Legacy configuration management issues delayed the demolition planning and assessing work scope. In addition, extensive on-line wiring updates were required prior to system removal.
- Increased design costs resulting from poor Design Agency performance and the inability of OPG to provide timely reviews of Design Agency documentation due to conflicting project priorities.
- Costs associated the non-standard size of the micro pile casing specified by the third party design agency as well as underestimating the quantity of grout material required for 24 micro piles and six test piles.
- Underestimating costs (labour and materials) related to the original scope of work.
- Increased direct costs related to the number of field changes requiring design package revisions that were necessary to correct design deficiencies and/or resolve material issues. Design package revisions required changes to work instructions, delaying field work. In some cases, design revisions imposed parts hold issues; i.e. availability, which further contributed to schedule delays.
- Increased indirect costs related to Contractor supervision and OPG project management oversight due to schedule delays.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2	Alt 3
Total Revenue	0	0	0	0	0
Base OM&A	(26,556)	0	0	0	0
Outage OM&A	0	0	0	0	0
Project OM&A	0	0	0	0	0
Total OM&A	(26,556)	0	0	0	0
Capital Expenditures	0	(16,277)	(1,821)	0	0
Present Value (PV)	(13,984)	(14,180)	(1,577)	0	0
Net Present Value (NPV)	N/A	(195)	12,408	0	0
IRR%	N/A	N/A	N/A	N/A	N/A
Discounted Payback (Yrs)	N/A	N/A	N/A	N/A	N/A

Base Case: Not Recommended - Stop the Project

To support Unit 2/3 Safe Storage Project de-watering milestones and place the Units in a safe state as a pre-requisite to decommissioning, the station will need to purchase and use 1,145 drums to drain the PHT system from both Units 2 and 3.

The option to use drums for permanent D_2O storage is not recommended. Increasing the volume of drums currently stored in the station reduces valuable floor space, poses extra safety hazards (tritium and conventional) and increases operator labour and resource efforts for the additional handling and movement of these drums, which translates into higher operational costs. The drum problem is exacerbated by the lack of capability to clean dirty drums at Pickering which causes housekeeping and dose issues that have drawn scrutiny from the regulator. A requirement to bring additional drums on site will only increase these concerns. Furthermore, the additional drums will partially negate the achievement made by the PNGS Common Services team who were corporately recognized for their contributions with the drum reduction program by developing an in-house process for removing high-TOC from over 2100 downgraded drums of D_2O. Purchasing over 1,100 drums for draining the 240Mg of heat transport water from the PHT system from Units 2 and 3 partially reverses the cost savings realized during the high-TOC D2O recovery program.

Alt. 1: Recommended - Continue Install. of 4x100Mg D2O Storage Tanks in UPPA Building

The recommended option is to continue installation of the four stainless steel storage tanks, each of 100 Mg D_2O capacity, within the Pickering UPP-A building as outlined in Section 4. To date, UPP-A demolition work is complete, detailed design work is complete, installation work is 90% complete and the Partial AFS has been approved. The storage tanks have been placed in service and currently store approx. 235 Mg. of low curie heavy water transferred from S&I. This release request includes provision for completing remaining installation work and support during commissioning to meet specified end date.

These four storage tanks provide a permanent means of D_2O storage for PHT heavy water from Units 2 and 3 and the excess capacity will provide the station with greater flexibility in D_2O management. The new tanks will improve Pickering's ability to perform bulk D_2O volume swaps to detritiate units that are close to or exceed their administrative limits for tritium concentrations in both moderator and PHT systems. This will also help reduce losses related to high fuel burn-up rates. The additional 400Mg of storage capacity will also provide a greater ability in blending and segregating various qualities of water to best suit station needs.

Alt. 2: Not Recommended - Delay Project

This option to delay Safe Storage Project is not recommended as OPG has made a commitment to the Board of Directors to complete Unit 2 and 3 Safe Storage project by March 2010. PNGS began receiving 240Mg of detritiated heavy water from Darlington TRF in June 2009 which is equivalent to the quantity of heavy water drained from Unit 2 moderator and PHT systems during drain process. Safe Storage Project must make storage capacity available since available storage within Supply & Inventory (S&I) system is minimal. Common Services agreed to temporarily store 250 Mg of heat transport water and 230 Mg of moderator water until Safe Storage Project was able to make additional storage capacity available; i.e. conversion of Unit 2 & 3 helium storage tanks to heavy water (high curie) storage tanks and the installation of the additional UPP storage tanks for storing low curie water. Presently, approximately 200 Mg of moderator water was transferred out of S&I and into the Unit 3 Helium tank to support P961 moderator swap outage pre-requisites. Common Services must transfer 230 Mg of low curie heavy water from S&I storage in preparation for transferring approx. 280 Mg of TRF, UPP and Sulzer product into S&I tanks. There is no other viable alternative for heavy water storage that will minimize P961 Outage delay costs and heavy water detritiation/upgrading costs other than to complete UPP Storage Project.

4/ THE PROPOSAL

Unit 2 and 3 Safe Storage Project resources will be utilized to execute the remaining tank installation scope of work for the project as recommended herein and endorsed by Safe Storage Project Management and Pickering A Site Management Board on March 30, 2007. The full release of $16,327k (including contingency) is requested to complete the D_2O storage tank installation; i.e. installation of four, 100 Mg capacity stainless steel storage tanks and auxiliary systems, including architectural and structural modifications within the UPP-A building. The remaining work includes civil/structural steel installation (internal/external stairs), tank commissioning and finally project close out.

The project deliverables are as follows:

- Complete removal of abandoned UPP-A process equipment (**COMPLETE**)
- Install and commission storage tanks including associated process equipment and controls **(98% COMPLETE)**
- Project management, design, field engineering, assessing and Ops support through to completion of field execution and close out phases of the project **(IN PROGRESS).**

Compensatory measures have been taken to accommodate the Unit 2/3 Moderator and PHT system heavy water respectively to support Unit 2/3 dewatering milestones until the UPP-A storage tanks are available for service. The Common Services Storage & Inventory (S&I) system has provided short term storage capacity for Unit 2 and Unit 3 heat transport water as well as increased detritiated D2O inventories received from Darlington Tritium Removal Facility, which began end of June 2009. The UPP tanks must be installed by Oct. 15/09 (N.B. Partial AFS declaration was approved Oct. 14/09) to facilitate D2O transfer and storage of the detritiated heavy water currently stored within S&I or risk impeding the station's ability to transfer moderator heavy water in and out of Unit 6 to support the P961 outage.

5/ QUALITATIVE FACTORS

Benefits to the Community/Regulator Relations

- Reliability: Additional storage capacity will permit bulk heavy water swaps and reduce heavy water swap frequency from once every year (current) to approximately once every three years.
- Housekeeping: Will address the long-standing problem of the large number of stored drums, to improve housekeeping and align with industry best practices and Nuclear Excellence principles.
- Reduced dose uptake by personnel: bulk heavy water swaps will ensure moderator tritium concentrations stay well below administrative limits to ensure dose uptake to plant personnel is kept as low as reasonably achievable.

Health and Safety

- Additional permanent D2O storage capacity eliminates the stations' dependency on additional drum storage, reducing the occurrences of drum handling related safety issues.
- The reduction of D2O drums reduces chances of D2O leak or spill and possible worker exposure to tritium during handling and storage.
- Bulk D2O swaps in the units will reduce tritium concentrations and dose commitments due to exposure during on-line maintenance activities.

Operational Considerations

- Elimination of additional D2O drum storage in the plant will help reduce operator workarounds, lowering the probability of human performance errors.
- Reduction in D2O drum use and storage will reduce this labour intensive practice and allow Operators to concentrate on running the station, improving productivity and operational flexibility.

6/ RISKS (see Attachment D for details)

Low = 1 to 3		Medium = 4 to 9		[illegible]	
	Impact				
	1	2	3	4	5
Probability 5	5	10	15	[illegible]	[illegible]
4	4	8	[illegible]	[illegible]	[illegible]
3	3	6	9	[illegible]	[illegible]
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Exceed target costs to complete submitted by Contractors	Installation phase is over 90% complete. A 15% Contingency has been included in cost estimate to address any additional field changes	9									2								
Schedule pressure to ensure tanks are available for service by Oct. 12/09 to support water transfers during P961 outage	Commissioning activities are I/P. A Control Maintenance team has been assigned to address discovery work related to deficiencies with system operation. Resources are available on days and afternoon shift to support as required to minimize schedule impact.		9									2							
Field changes resulting from deficiencies in design and/or construction workmanship.	Approx. 5000 hrs remaining to complete construction activities. Structural steel installation constitutes bulk of remaining work. Sufficient contingency has been included to address potential scope changes. Schedule risk is low due to nature of work.			3									3						

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Nov 2009	May 2010	Manager, Common Services

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Available inventory increase to Supply & Inventory management	Current volume - 450Mg in UPP and 200Mg in S&I for low curie D2O storage.	Increased inventory volume available to station once tanks are AFS'd	Confirm 400Mg inventory increase to S&I system	Common Services
2.	Reduction of drums used for heavy water storage	Over 200Mg of heavy water was removed from drums, cleaned and transported to Darlington TRF for detritiation. Aprox. 2,700 empty, dirty drums reside in the station at PNGS.	Approx. 240Mg of PHT heavy water will be drained to new UPP storage tanks during SS Project. Any additional heavy water stored in the UPP storage tanks decreases / eliminates need for drum storage.	Measure UPP-A heavy water inventory in new storage tanks.	Common Services
3.	Delay to P961 Outage	UPP storage tanks to be declared available for service by Oct. 15/09 or negatively impact P961 outage (day for day delay).	Drain approx. 140Mg of reactor grade heavy water from S&I to the UPP storage tanks by Oct. 26/09.	Measure UPP-A heavy water inventory in new tanks by Oct. 26/09 (CS Ops confirmed storage tanks stored over 200Mg of heavy water as of Oct. 26/09 at 4:15 p.m.)	Common Services
4.	Reduced moderator water tritium concentrations	Detritiated heavy water from Darlington TRF will be returned to PNGS between Oct. 12 and Feb 2010. Approx. 235 Mg of low curie heavy water will be transferred from S&I to UPP-A storage tanks.	Utilize low curie heavy water stored in UPP-A storage tanks to support moderator swap in either Unit 4 or Unit 1.	Verify schedule for planned moderator swap to lower overall moderator tritium concentrations and confirm low curie heavy water is supplied from UPP-A storage tanks.	Common Services

NOTE: A detailed Lessons Learned meeting will be conducted with all the project stakeholders following the Final AFS to identify areas for improvements. A final Lessons Learned Report will be issued by the project. A comparison of the actual versus perceived project risks will also be reviewed and documented for future reference.

Appendix "A" — Glossary (acronyms, codes, technical terms)

BHWP: Bruce Heavy Water Plant
BQE: Budget Quality Estimate
COMS: Constructability, Operability, Maintainability and Safety
CWP: Comprehensive Work Package
D/G: Down Graded
EC: Engineering Change
IRR: Internal Rate of Return
IXCU: Ion exchange column clean up
MOL: Ministry of Labour
NPV: Net Present Value
OM&A: Operating, Maintenance and Administration
OP&Ps: Operating Policies & Procedures
OPGN: Ontario Power Generation Nuclear
PHT: Primary Heat Transport (System)
R/G: Reactor Grade
RTS: Return to Service (Project)
S&I: Supply and Inventory
SS: Safe Storage
TOC: Total Organic Carbon
TRF: Tritium Removal Facility
TSSA: Technical Standards and Safety Authority
UPPA: Heavy Water Upgrading Plant, Pickering A
VLLDS: Very Low Level Drain State

Appendix "B"

Project Funding History

$ 000's Release Type	Month	All Existing and Planned Releases (incl contingency) Cumulative Values Year	2006	2007	2008	2009	2010	2011	2012	Later	Total
Developmental	Nov	2006	168	681							849
Full	Mar	2007	168	10,146	857						11,171
Superseding	Feb	2009	168	10,146	857	3,286					14,457
Superseding	Sep	2009	168	10,146	857	4,368	789				16,327
											0
											0
											0
											0

LTD Spent	Sep	2009	168	3,400	4,318	6,363					14,249

Comments:

Appendix "C"

Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	None	SR & D Opportunity	No
Progress Payments	Yes	Foreign Currency	N/A	Retainer Fee	No
Income Tax Rate	Generation	PST	No	Interest Rate (Capital)	6%
Depreciation Rate (Capital)	Generating Equipment 8%	Leasing	No	Indexed Priced Contract	N/A

Comments:

Base Case Assumptions:

- One time drumming costs of $1.4M
- Yearly rental for drum storage: $386k/yr escalated @ 3%/yr
- Lack of S&I contributes $234k/yr/Unit in increased fuel burn-up as a result of reduced D2O isotopic
- D2O detritiation results in a dose savings of $720k

Project Cost Estimate:

Design Complete	100%	Quality of Estimate	Release + 15% to - 10%	3rd Party Estimate	Yes
Reviewed by Sponsor	Yes	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	No	Budgetary Quote(s)	Yes	First Unit Actual Used	No
Cost Sharing	No	Contracts in place	Yes	Competitive Bid	No
Fixed Price Contract	No	Fee for Service	Yes	Firm Vendor Proposal	No

Comments:

Rationale for Cost Classification:

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)							
Pickering A	1			N/A									
	4												
Pickering B	5			N/A									
	6												
	7												
	8												
Darlington	1			N/A									
	2												
	3												
	4												

Comments:

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Impact on Revenue

$000's	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate KWH										
Probability										0.0%
Consequence										0
Risk										0
Other										0
Base Case	0	0	0	0	0	0	0	0	0	0
Probability										0.0%
Consequence										0
Risk										0
Other										0
Recommendation	0	0	0	0	0	0	0	0	0	0
Net Impact	0	0	0	0	0	0	0	0	0	0

Comments:

Project has no impact on OPG Nuclear Revenue

Impact on OM&A

$000's	Present	2010	2011	2012	2013	2014	2015	2016	Later	Total
Base OM&A	(3,366)	(2,029)	(2,047)	(1,946)	(1,858)	(1,871)	(1,884)	(1,897)	(9,658)	**(26,556)**
Outage OM&A										0
Project OM&A										0
Base Case	**(3,366)**	**(2,029)**	**(2,047)**	**(1,946)**	**(1,858)**	**(1,871)**	**(1,884)**	**(1,897)**	**(9,658)**	**(26,556)**
Base OM&A										0
Outage OM&A										0
Project OM&A										0
Recommendation	0	0	0	0	0	0	0	0	0	0
Net Impact	3,366	2,029	2,047	1,946	1,858	1,871	1,884	1,897	9,658	26,556

Comments:

PNGS-A PHT D2O Storage Tank Project (U2/3 SS Project) 13 - 46576
Superseding Business Case NA44 - BCS - 38000 - 00002 – R004

Attachment "A" **Project Cost Summary**

	$000's Capital	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnt & Support	529	393	132						1,054
	Engineering	338	160	259						757
	Procurement	436	822							1,258
	Construction	6,257	5,738	95						12,090
	Other									-
										-
										-
										-
										-
										-
	Interest (Capital Project Only)	328	540							868
	Project Costs	**7,888**	**7,653**	**486**	**-**	**-**	**-**	**-**	**-**	**16,027**
	General Contingency		-	300						300
	Specific Contingency									-
	Project Costs	**7,888**	**7,653**	**786**	**-**	**-**	**-**	**-**	**-**	**16,327**
Cash	**Adjust to Cash Basis + / -**								-	-
	Project Costs	**7,888**	**7,653**	**786**	**-**	**-**	**-**	**-**	**-**	**16,327**
Funding	**Currently Released**	8,367	6,089							14,456
	This Release		1,227	786						2,012
	Future Release									
	Project Funding	**8,367**	**7,316**	**786**	**-**	**-**	**-**	**-**	**(141)**	**16,327**

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

		LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Budget	**2009-2013 Business Plan**		4,029	64						4,093
	Variance to Business Plan		**3,624**	**422**	**-**	**-**	**-**	**-**	**-**	**4,046**
Other	**Removal Costs included above**									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

The estimated variance(s) to the **2009-2013 Business Plan** will be addressed through the portfolio management process.
A PCRAF **is not required** .

Reviewed By: [signature]

Anthony Colella
Project Manager

Date:

Approved By: [signature]

Scott Guthrie
Strat IV Manager

Date:

PNGS-A PHT D2O Storage Tank Project (U2/3 SS Project) 13 - 46576
Superseding Business Case NA44 - BCS - 38000 - 00002 – R004

Attachment "B" **Project Variance Analysis**

	Capital	LTD Sep 2009	Total Project: Last BCS Feb 2009	Total Project: This BCS Sep 2009	Variance	Comments
Scores Basis	Project Mgmnt & Support	1,055	1,192	1,367	176	See Note 1 - increased overhead/commissioning support
	Engineering	362	461	644	182	See Note 2 - rework/increased overhead
	Procurement	1,161	1,325	1,258	-67	FEA initiated changes to material reqm'ts
	Construction	10,943	10,013	11,890	1,878	See Note 3 below - scope changes/delays
	Other				0	
					0	
					0	
					0	
					0	
	Interest (Capital Project Only)	728	717	868	151	
	Project Costs (Scores Basis)	**14,249**	**13,707**	**16,027**	**2,320**	
	General Contingency		749	300	-449	
	Specific Contingency				0	
	Project Costs (Scores Basis)	**14,249**	**14,456**	**16,327**	**1,871**	

Other	**Removal Costs included above**				0	
	Inventory to be written off				0	
	Spare Parts in Inventory				0	

Comments:

VARIANCE EXPLANATION

The project capital costs have been consolidated into 5 cost reporting centres listed above compared to the 7 cost centres listed in previous BCS submittals. Therefore, the Project Management & Support costs includes OPG PWU labour support costs and the newly created Construction cost centre includes costs related to labour and construction Purchased Services contracts; i.e. construction and construction support contracts, the design agency contract and contractors hired as augmented staff within Safe Storage Project Engineering, Design and Assessing departments.

Notes:

1. Project Management overhead costs increased due to the six month delay during field execution. The Partial AFS date was delayed 6 months (24 weeks) increasing project management costs above original estimate. In addition to the increased over head costs, the 180 FEAs also created re-work within the Assessing and Design organizations; re: revising CWPS and issuing Design Change revisions.

	Description	Hrs	Cost (@75/hr)
MTL:	24 wks x40 hrs/wk x 1 FTE	960	$72,000
Assessing Rework:	~150 CWP revisions processed (to incorporated 180 FEAs) x 5 hrs/revision	750	$56,250
			$128,250

2. The increase in engineering costs is attributed to both schedule delays and the poor quality of the design ECs issued for this project. The 6 month schedule delay increased overhead costs related to extending DTL services over that duration. Furthermore, the poor quality of design documents issued by the Design Agency requied over 180 field changes (i.e. Field Engineering Authorization or FEAs) to correct the designs, which were issued after the February superseding BCS was initiated. FEA preparation most often requires field walk downs with contractors to review design issue and agree to proposed solution. FEAs, on average take 4 hours to prepare and issue. EC revisions are also required to incorporate the FEAs once they are approved by Design. There were 20 Design EC revisions issued since February 2009 to incorporate the 180 FEAs. The cost increases are summarized in the table below:

	Description	Hrs	Cost (@75/hr)
DTL costs	24 wk delay x 24 hrs/wk x 1 FTE	576	$43,200
FEA preparation	180 FEAs x 5 hrs/FEA	900	$67,500
Design EC revisions to incorporation FEAs	20 Design EC revs x 12 hrs/revision	240	$18,000
			$128,700

3. The Construction costs extras are related to increase to both construction contractor cost extras as well as increases in augmented staff costs; i.e: Field Team Leader (FTL) overhead costs. These costs are summarized below:

Construction cost extras:

- The Mechanical/Electrical Contractor and the Civil Contractor reported cost extras related to working overtime to support original schedule milestones, increased training costs and increased costs related to design field changes (issued by Safe Storage Project as Field Engineering Authorizations or FEAs), which have increased the installation "costs to complete" originally estimated in January 2009. The Mechanical Contractor also underestimated the original scope of work as reported in their costs reports submitted to OPG. Furthermore, the 6 months schedule delay has also increased both Contractor's Project Management Team's (PMT) costs (ref. Contractor's cost report). These costs are summarized below:

	Description	Hrs	Cost
Mechanical/Elec. Contractor	Total value of Cost Change Requests reported by Contractor related to FEAs/training		$101,000*
Mechanical/Elec. Contractor	Increased in PMT costs reported by Contractor		$281,000
Mechanical/Elec. Contractor	Increase in actual costs to execute original scope of work as reported Jan. 28/09		$473,000
Civil Contractor	Total value of Cost Change Requests (additional scope) including PMT costs increases		$349,000
Increased FTL costs	Field Team Leader supporting this project is a Contractor. Project delay has increased project overhead costs 1 FTL x 24 wks x 60hrs/wk = 1440 hrs @ $85/hr.		$122,400
Waste collection/slurry separation	Project delays increased rental costs for slurry separation bins		$49,200
Increased Staff Augmentation costs	Design Agency provided one Design Engineering on augmented staff basis during micro pile installation. Contract was extended 1 month due to field delays.		$48,322
Soil Sampling	Increased scope due to increased quantity of soil samples required for disposal segregation, increased quantity of compaction testing (micro pile grout samples) that needed to taken. (cost estimate only allocated $70k for soil samples/compaction testing)		$190,000
			$1,613,922
		Total Extras:	$1,870,872

Attachment "C" **Milestones and In Service Declarations**

Key Milestones

Completion Date			Description
Day	Mth	Yr	
14	Oct.	2009	Partial AFS – storage tanks in service to support P961 outage
15	Dec.	2009	Final AFS – internal stair installed, external stair enclosure installed, breathing air, service air and fire protection interferences re-installed.

A Project Execution Plan (PEP) **was approved in Nov 2008**

In Service Declarations: **(Capital Only)**

Month	Year	Description	$ 000's	%
Oct.	2009	Mechanical, electrical and I&C installations complete. Storage tanks placed in service.	$14,238	91.6%
Dec.	2009	Civil/Structural installation complete	$1,300	8.4%

Attachment "D"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 months)	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges **OR** Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages **OR** Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

U1 & U4 Calandria Vault Dryer Augmentation 13 - 49252

Superseding Business Case NA44 - BCS - 72250 - 00003 – R000

1/ RECOMMENDATION:

Approval is requested for this Superseding Release of $10,972k Capital, to complete installation of the new Calandria Vault Dryers in Pickering A Unit 1 and Unit 4.

The Business Objective of this project is to reduce the very significant generation risk associated with corrosion of carbon steel components inside the Calandria vault (such as Ring Thermal Shield bracket, Biological Shield Cooling pipe work, hangers, tank support legs) by installing a more reliable Calandria Vault Dryer system with an optimum availability (as close to 100% as achievable). A more reliable system will ensure that the dew point levels are maintained within the acceptable limits thereby minimizing corrosion and the risk of component failures. A high availability will protect life-limiting components in the Calandria vault from the cumulative effects of corrosion. In addition, this will minimize the forced outage risks and potential early unit end-of-life due to exceeding operational dew point limits.

A previous Full Release of $7,173k was approved in August 2006. This Superseding Release is required to cover the cost overruns resulting from issues and delays during completion of detailed design and installation of the Unit 4 dryers. These costs include a major revision to the equipment Technical Specification due to changes in coolant medium from refrigerant to LPSW, low installation estimate from the contractor, delays in obtaining materials, delays due to permitry issues at the beginning of Unit 4 installations, and extensive overtime costs in an effort to complete Unit 4 execution work prior to the start of the P941 Outage (beginning on January 6, 2009). Further Unit 4 execution delays were encountered due to work area restrictions and interference with high priority P941 Outage work (i.e. fission chamber related work). The sum of these delays and issues has resulted in external OPG costs totaling some 3M$ more than the previous release, and total project costs 3.8M$ over the Full Release. (A more complete explanation is provided in the Project Variance Analysis page 12).

The status of the project is as follows:

- Detailed engineering complete.
- Installation of Unit 4 dryers completed March 2009; commissioning in progress.
- Installation of Unit 1 dryers planned to start in August 2009.
- In-service of Unit 1 dryers planned for November 2009.

$000's (incl contingency)	Type	LTD 2008	2009	2010	2011	2012	2013	Later	Total
Currently Released	Full	7,173							**7,173**
Requested Now	Superseding	(1,805)	5,512	92					**3,799**
Future Funding Req'd	None								**-**
Total Project Costs		**5,368**	**5,512**	**92**	**-**	**-**	**-**	**-**	**10,972**
Non Project Costs									**-**
Grand Total		**5,368**	**5,512**	**92**	**-**	**-**	**-**	**-**	**10,972**
Investment Type **Sustaining**		**Class** **Capital**		**NPV** **72M$**		**IRR** **n/a**		**Discounted Payback** **n/a**	

Submitted By:

6 APR 2009

Mark Elliott
Senior VP, Pickering A
Date:

Finance Approval:

April 7 2009

Randy Leavitt
VP, Nuclear Finance
Date:

Line Approval (Per OAR Element 1.4 Variance):

April 15 2009

Tom Mitchell
Chief Nuclear Officer
Date:

2/ BACKGROUND & ISSUES

The Calandria vault in Pickering 'A' is designed to provide biological shielding for the reactor in addition to being a containment vessel and a structural support for reactor equipment. The Calandria vault was intended to be a dry and closed space. Increased moisture levels in the vault are as a result of leakages.

The radiolysis of the moist air in the vault produces nitric acid which causes corrosion of components made of carbon steel in the vault, such as dump tank support legs, Ring Thermal Shield (RTS) brackets, hangers and Biological Shield Cooling (BSC) pipe work. The concentration of nitric acid on the component surfaces increases with increased moisture in the vault air. Any component failure within the Calandria vault represents a serious generation risk, as inspections and/or repairs would require extensive outage durations and expense. Some component failures (RTS brackets, RTS cooling) could precipitate failures which would render the unit beyond repair. The Calandria Vault Dryer removes moisture (which has a low pH) from the air inside the vault which reduces condensation on the exposed surfaces, minimizing the corrosion of the carbon steel components. (For more background information, see Section 2 of the Full Release BCS, NA44-BCS-72250-00002).

The existing Calandria Vault Dryer (CVD) system has demonstrated reliability problems due to design deficiencies, which makes the system susceptible to corrosion itself, and high equipment maintenance.

Preliminary and Detailed Engineering has determined that using the current design requirement of 2250 SCFM and the existing space in the Reactor Building, a two dryer system (2 x 100% - redundancy) will be capable of a 4 kg/hr continuous capacity removal rate which is greater than twice the maximum condensate removal rate recorded by the existing dryer system. The new dryers will use LPSW as a chiller to cool the vault air prior to dehumidification and to post-cool the air prior to return to the vault.

The Design EC packages have been issued for both Units 1 and 4. Dryers for both Units 1 and 4 have been procured. The Unit 4 packages have subsequently been revised due to issues that arose during field installation. The installation of the Unit 4 dryers is complete and the commissioning of these dryers is now in progress.

This superseding BCS is required to complete the design EC revisions in Unit 1, install and commission the Unit 1 dryers, and complete project closeout activities. The original release has been exhausted due to increased costs and delays in the design process and the installation of the Unit 4 dryers. The Design Agency costs have increased > $1,000k from the original estimate and the contract installation costs have increased > $2,000k (refer to Attachment B for breakdown of these variances). This BCS cost estimate is based on the actual costs spent to complete Unit 4 installation, and the anticipated costs to complete Unit 1 based on walkdowns performed by field engineering.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Do Nothing in Unit 1	Alt 3 Install One Dryer in U1	Alt 4 Delay Unit 1 Installation	Alt 5
Revenue							
OM&A							
Capital		(10,972)	(4,226)				
Present Value (PV)	(75,500)	(9,156)	(3,455)				
Net Present Value (NPV)	**N/A**	**66,344**	**72,045**				
Internal Rate of Return (IRR) %	N/A	n/a	n/a				
Discounted Payback (Yrs)	N/A	n/a	n/a				

Base Case: No Project
Since the project is approximately two-thirds completed, this is no longer an option.

Alt. 1: Recommended - Complete Installation of Modification in Unit 1
The existing Calandria Vault Dryer in Unit 1 is unreliable and exhibits a high failure rate, and replacement parts are becoming obsolete, so continual operation and maintenance of this dryer is problematic. The unavailability of the dryer can cause high corrosion risk for the calandria vault structures and Ring Thermal Shield (RTS) bracketing. Long-term degradation of components within the vault could lead to irreparable damage and the premature unit end-of-life. The costs of purchasing the new dryers have already been incurred along with the design engineering costs. All supplementary materials for Unit 1 modifications have been purchased. An installation contract has also been awarded.

Alt. 2: Not Recommended - Do Nothing in Unit 1
It is not recommended to not complete installation of modifications in Unit 1 (leave existing Unit 1 Calandria Vault Dryer as is). The costs of purchasing the 2 new dryers have already been incurred along with the design engineering costs. All supplementary materials for Unit 1 modifications have also been purchased. The Station will continue to be burdened with excessive repairs on the existing unreliable dryer. Any component failure within the vault represents a serious generation risk, as inspections and / or repairs would require extensive outage durations and costs, and long-term degradation could lead to irreparable damage and premature unit end-of-life. (Thus, this alternative has not been financially evaluated).

Alt. 3: Not Recommended - Do Less: Install One Dryer in Unit 1
It is not recommended to partially complete the modifications in Unit 1 (i.e. install only one new dryer). The costs of purchasing the 2 new dryers have already been incurred along with the design engineering costs. Partial installation would require a revision to the Design EC packages, which would delay the execution and closeout schedule. The Station requirement for 100% redundancy and maximum availability would not be satisfied. (Thus, this alternative has not been financially evaluated).

Alt 4: Not Recommended - Delay Unit 1 Installation
It is not recommended to delay installation of Unit 1 modifications until next year (2010) or later. Costs for material and equipment storage will be incurred until installation begins. A new installation contract may need to be negotiated (installation costs may be subject to change). The Station will continue to be burdened with excessive repairs on the existing unreliable dryer until the new dryers are installed. (Thus, this alternative has not been financially evaluated).

4/ THE PROPOSAL

The superseding release will be used to revise the Unit 1 design EC package, complete the installation and commissioning of the Unit 1 dryers, and complete project close-out activities.

The following are the objectives and expected results for this superseding business case summary:

- Unit 1 design EC revision
- Installation of modifications in Unit 1
- Commissioning of Unit 1 dryers
- Project close-out activities for both Units 1 & 4

5/ QUALITATIVE FACTORS

- Reduce the amount of time dryer is out of service (and the amount of time above Action Level 1)
- Reduce maintenance efforts / time spent on maintaining the system

6/ RISKS (see Attachment D for details)

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
		Impact			
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Trolley Crane Modification	Perform walkdowns	3	9	3	3	3	3	3	3	**9**	2	4	2	2	2	2	2	2	**4**
Availability of Resources	Coordinate with Contractor – assign dedicated resources	3	6	3	3	3	3	3	3	**6**	1	1	1	1	1	1	1	1	**1**
Field Conditions do not match Design details	Perform walkdowns, field verification	3	9	9	3	3	3	3	3	**9**	2	4	2	2	2	2	2	2	**4**
Other Station priorities making work area inaccessible	Coordinate with Work Control and Operations to mitigate impacts	2	4	2	2	2	2	2	2	**4**	2	2	2	2	2	2	2	2	**2**
Equipment is damaged during Installation	PJBs, experienced trades, installation support from manufacturer	3	9	6	3	3	3	3	3	**9**	2	2	2	2	2	2	2	2	**2**
Escalation of Design Agency costs	Monitor costs and scope growth	3	9	9	3	3	3	3	3	**9**	2	4	2	2	2	2	2	2	**4**
Execution delay due to RB / SAA conditions	Communicate with OPS / ANO regularly to monitor field conditions	4	12	4	4	4	4	4	4	**12**	3	6	3	3	3	3	3	3	**6**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Nov 2009	May 2010	Manager, Performance Engineering

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Dew Points	-8 degrees Celsius	≤ -8 degrees Celsius dew point maintained at vault inlet	Shift log reviews	Operations
2.	Temperature	45 degrees Celsius	Dryer outlet air temperature of 45 degrees Celsius	Shift log reviews	Operations
3.	Availability	No baseline existing	≥ 95% dryer availability	Shift log reviews	Operations
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

Acronym	Meaning
AFS	Available for Service
ANO	Authorized Nuclear Operator
BCS	Business Case Summary
BSC	Biological Shield Cooling
CCN	Contract Changes Notices
CVD	Calandria Vault Dryer
EC	Engineering Change
LPSW	Low Pressure Service Water
LTD	Life-to-Date
NPV	Net Present Value
OPS	Operations
PEP	Project Execution Plan
PIR	Post Implementation Review
PJB	Pre-Job Briefing
RB	Reactor Building
RTS	Ring Thermal Shield
SAA	South Accessible Area
SCFM	Standard Cubic Feet per Minute
TCD	Target Completion Date

Appendix "B" Project Funding History

		Cumulative Values									
Release Type	Month	Year	2005	2006	2007	2008	2009	2010	2011	Later	Total
Developmental	Sep	2005	325	0	0	0	0	0	0	0	325
Full	Aug	2006	325	602	3,246	3,000					7,173
Superseding	Mar	2009	37	547	700	4,084	5,512	92			10,972
											0
											0
											0
											0
											0

LTD Spent	Feb	2009	37	547	700	4,084	1,179				6,547

Comments:

The above LTD spending amount is as stated in the Week 024 report.

Appendix "C" Financial Model – Assumptions

Financial Assumptions:

Discount Rate		Cost Escalation (yr)		SR & D Opportunity	
Progress Payments		Foreign Currency		Retainer Fee	
Income Tax Rate		PST		Interest Rate (Capital)	
Depreciation Rate (Capital)		Leasing		Indexed Priced Contract	

Comments:

Project Cost Estimate:

Design Complete	100%	Quality of Estimate	Release + 15% to - 10%	3rd Party Estimate	No
Reviewed by Sponsor	Yes	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	Yes	Budgetary Quote(s)	Yes	First Unit Actual Used	Yes
Cost Sharing	No	Contracts in place	Yes	Competitive Bid	Yes
Fixed Price Contract	No	Fee for Service	N/A	Firm Vendor Proposal	Yes

Comments:

Rationale for Cost Classification:

Capital – replacing life-expired equipment.

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)						
Pickering A	1	N/A	N/A	N/A	N/A							
	4	N/A	N/A									
Pickering B	5	N/A	N/A	N/A	N/A							
	6	N/A	N/A									
	7	N/A	N/A									
	8	N/A	N/A									
Darlington	1	N/A	N/A	N/A	N/A							
	2	N/A	N/A									
	3	N/A	N/A									
	4	N/A	N/A									

Comments:
Non-Outage work.

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Impact on Revenue

$000's	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate KWH										
Probability										0.0%
Consequence										0
Risk										0
Other										0
Base Case	0	0	0	0	0	0	0	0	0	0
Probability										0.0%
Consequence										0
Risk										0
Other										0
Recommendation	0	0	0	0	0	0	0	0	0	0
Net Impact	0	0	0	0	0	0	0	0	0	0

Comments:

Impact on OM&A

$000's	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A										0
Outage OM&A										0
Project OM&A										0
Base Case	0	0	0	0	0	0	0	0	0	0
Base OM&A										0
Outage OM&A										0
Project OM&A										0
Recommendation	0	0	0	0	0	0	0	0	0	0
Net Impact	0	0	0	0	0	0	0	0	0	0

Comments:

Not Applicable.

U1 & U4 Calandria Vault Dryer Augmentation 13 - 49252
Superseding Business Case NA44 - BCS - 72250 - 00003 – R000

Attachment "A" **Project Cost Summary**

	$000's Capital	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnt & Support	806	411	57						1,274
	Engineering	1,924	559	35						2,518
	Procurement	1,033	1,107							2,140
	Construction	1,423	2,918							4,341
	Other									-
										-
										-
										-
										-
	Interest (Capital Project Only)	182	172							354
	Project Costs	**5,368**	**5,167**	**92**	**-**	**-**	**-**	**-**	**-**	**10,627**
	General Contingency		345							345
	Specific Contingency									-
	Project Costs	**5,368**	**5,512**	**92**	**-**	**-**	**-**	**-**	**-**	**10,972**
Cash	**Adjust to Cash Basis + / -**								-	-
	Project Costs	**5,368**	**5,512**	**92**	**-**	**-**	**-**	**-**	**-**	**10,972**
Funding	**Currently Released**	7,173								7,173
	This Release		3,707	92						3,799
	Future Release								-	-
	Project Funding	**7,173**	**3,707**	**92**	**-**	**-**	**-**	**-**	**-**	**10,972**

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

		LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Budget	**2009-2013 Business Plan**	5,332	261	-						5,593
	Variance to Business Plan	**36**	**4,906**	**92**	**-**	**-**	**-**	**-**	**-**	**5,034**
Other	**Removal Costs included above**									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

The estimated variance(s) to the **2009-2013 Business Plan** will be addressed through the portfolio management process.
A PCRAF **is not required** .

Reviewed By: 3/13/2009

E. H. Wong
Project Manager

Approved By: 16 Mar 2009.

N. Rahman
Strat IV Manager

Date:

U1 & U4 Calandria Vault Dryer Replacement 13 - 49252
Superseding Business Case NA44 - BCS - 72250 - 00003 – R000

Attachment "B" **Project Variance Analysis**

	Capital	LTD Feb 2009	Total Project Last BCS Aug 2006	Total Project This BCS Mar 2009	Variance	Comments
Scores Basis	Project Mgmnt & Support	863	330	1274	944	See Note 1
	Engineering	2018	490	2518	2028	See Note 2
	Procurement	1075	2500	2140	-360	Based on total materials cost in Unit 4
	Construction	2362	1880	4341	2461	See Note 3
	Other		0		0	
					0	
					0	
					0	
					0	
	Interest (Capital Project Only)	229	393	354	-39	In-Service Declaration in April and Nov 2009 for Unit 4 & Unit 1 respectively
	Project Costs (Scores Basis)	**6547**	**5593**	**10627**	**5034**	
	General Contingency		**1580**	**345**	-1235	10% contingency on superseding funds
	Specific Contingency				0	
	Project Costs (Scores Basis)	**6547**	**7173**	**10972**	**3799**	

Other	Removal Costs included above				0	
	Inventory to be written off				0	
	Spare Parts in Inventory				0	

Notes:

Note 1 - Increased Project Management Support Costs

- Extended project schedule due to deferrals to support other higher priority work (i.e. ISTB), late design issuance and prolonged Unit 4 execution
- Recovery plan required additional resources and overtime (i.e. to expedite material delivery, resolve material issues)

Note 2 – Increased Engineering Costs

- Late design package issuance due to engineering and management issues (25 Contract Change Notices have been submitted by the Design Agency totaling > $800k):
  - change in design requirement from refrigerant cooling to low pressure service water, which required a revision to the Technical Specification
  - overlooked maintenance requirements resulting in extensive platform design modification
  - redesign of dryers due to unaccounted for pressure drop in ducting system
  - scope addition to relocate interfering breathing air stations
  - unanticipated iterative manufacturer drawing review cycle
  - change in outage schedule and priority so level of efforts needed to be adjusted
  - change in designers while project was put on hold
- Unit 4 design quality issues requiring numerous field changes (design revision costs totaling ~ $200k)
- Additional detailed oversight of Design Agency work due to poor quality deliverables
- Pending costs include Unit 1 design EC revision and Unit 1 & Unit 4 closeout activities

Note 3 – Increased Installation Costs

- Additional resources and overtime required to complete Unit 4 work assessments and maintain the schedule
- Complex installation resulted from all the design changes (Contractor's proposal was $675k above the original estimate per unit in the Full Release BCS, which total $1,350k in variance for both units)
- Accelerated Unit 4 execution schedule in attempt to complete work prior to P941 outage (Contractor premium costs totaling ~ $200k)
- Unit 4 execution schedule delays totaling > $600k due to:
  - late material delivery
  - permitry issues
  - restrictions on amount of scaffolding allowed in Reactor Building while unit is running
  - numerous field changes resulting from design quality issues
  - late identification of catch containment requirement
  - resources diverted to support P941 outage / interference with P941 work
  - underestimated pre-fabrication work and schedule

Attachment "C" **Milestones and In Service Declarations**

Key Milestones

Completion Date			Description
Day	Mth	Yr	
20	06	2009	Unit 1 Work Order Task Assessment Complete
20	08	2009	Unit 1 Start of Installation T-0
15	11	2009	Unit 1 AFS of Dryers
15	11	2010	Project Complete Milestone

A Project Execution Plan (PEP) **will be approved by May 2009**

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%
Apr	2009	Equipment In-Service Declaration for Unit 4	5,497	50%
Nov	2009	Equipment In-Service Declaration for Unit 1	5,475	50%

Attachment "D"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 months)	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges **OR** Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages **OR** Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

PNGS-A Switchyard Relay Building Replacement Project 13 - 49266

Full Release Business Case Summary NA44-BCS-65130-00002-R000

1/ RECOMMENDATION:

We **recommend a Full Release of $7,452K (including contingency of $1,720K)** to complete the commissioning of a new Unit 012 Protection, Control & Telecom (PCT) interface with Hydro One and preparations for Unit 034. This BCS covers the OPG portion of this Joint Project; Hydro One is funding the work related to their property and equipment.

The business objective of this project is to **improve the reliability of the station's Main Output system**. Failure to properly interface OPG equipment with new Hydro One switchyard protection and control systems will leave the station vulnerable to forced outages and associated financial losses. This will be achieved by modifying OPG equipment and systems to interface with the new PCT system being installed by Hydro One in the PNGS-A switchyard. The new PCT system will utilize an independent dual redundant design philosophy to comply with current NPCC/IESO guidelines to provide full separation of A and B protection channels in the switchyard.

This project will be **executed in several phases between 2007 and 2010**. Initial installation of the new PCT system and interfaces for Unit 012 will be undertaken during P711 in Fall 2007 followed by similar modification for Unit 034 in P841 (2008). Remaining work, including DCC alarm update, Sequence of Event Recorder update and final update of associated design documents, will be staged and implemented online or during successive outages as required in 2009 & 2010.

The installation of the trench, duct bank, cabling and terminal boxes have been covered under the **Partial Release of funding**. Refer to section 2.0 "Background & Issues" for additional information.

Full release funding is required now to **meet P841 milestones** and to **complete commissioning of U1/2** during P711. Refer to section 2.0 "Background & Issues" for additional information.

$000's (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	Partial	-	260	8,060					8,320
Requested Now	Full	-		1,125	3,350	1,867	841	269	7,452
Future Funding Req'd	None								-
Total Project Costs		-	260	9,185	3,350	1,867	841	269	15,772
Other Costs									-
Ongoing Costs									-
Grand Total		-	260	9,185	3,350	1,867	841	269	15,772
Investment Type Value Enhancing		Class Capital		(IEV) Impact on Ec Value 19,699		IRR 27.4%		Discounted Payback 7.3	

Submitted By:

16 OCT 2007

for M. Elliott
Site VP, Pickering A
Date:

Finance Approval:

Oct 29/07

D. Power
Director Investment Management
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Oct 31/07

P.R. Charlebois
EVP and COO
Date:

2/ BACKGROUND & ISSUES

As a result of a **major fire in early 2006 (SCR-P-2006-05953/07053)**, the **PCT equipment** in PNGS-A switchyard relay building **was damaged beyond repair**. Further investigation revealed a significant number of fire-damaged cables inside cable trenches in the relay building. The extent of the damage forced Hydro One and OPG to bypass the damaged relay building equipment with a **temporary protection & control solution** in order to maintain connection of Pickering A units to the grid.

Additionally, OPG Engineering & Maintenance and Hydro One observed **significant degradation of existing cables** connecting the station with the switchyard as a result of aging and submersion in water for extended durations. This condition also influenced Hydro One's final decision to **install a new PCT system** compliant with current NPCC/IESO guidelines. This modification will **enhance reliability of the switchyard** as well as **comply with current market rules** for the Bulk Electricity System. OPG is also obligated to operate within these guidelines.

OPG will **install new trenches, duct banks and cabling from the switchyard to the station** and modify the wiring as required to support the Hydro One independent and fully separated dual protection channel initiative.

Hydro One is responsible for installation costs related to the upgrade/replacement of their equipment. OPG is responsible for the costs related to the upgrade/replacement of OPG-owned equipment.

The **Unit 2/3 Safe Storage Project will be responsible** for costs associated with Unit 2/3 specific work not covered under the scope of this project. This project will ensure the ring bus protection for the Unit 2 & 3 SST is restored.

To meet these **objectives the project** will undertake the following:

- Design, install and commission a new interface for system interconnectivity between Hydro One and OPG station equipment.
- Implement revised Alarm and SOER signals from switchyard consistent with current standards.
- Update related design, operating and maintenance documents.

The scheduling of the project will be staged from 2007 thru 2010 outages with the initial primary focus to install and commission system interconnectivity between the station and the new PCT system on Units 012 during the P711 outage and Units 034 during the P841 outage.

The following **work has been completed** under the **Partial Release, NA44-BCS-65130-00001: $6.3M**

- Detailed design for all civil (U12/34) and U1/2 Electrical
- Installation of the East and West trench from the powerhouse to the security fence.
- Installation of cable duct from security fence to switchyard. Installation of a cable vault for the demarcation point.
- Installation of Marshalling boxes inside powerhouse and demarcation boxes in the switchyard.
- Installation of wall & floor penetrations in the powerhouse for new cable trays.
- Installation of new cable trays inside powerhouse and inside of the trenches.
- Pulling of new power cabling from the powerhouse to the new ATS building in the switchyard.
- Installation of two new circuit breakers for 600V power supply to the new ATS building. This work has completed a successful AFS.
- Pulling of new protection and control (P&C) cabling for U1/2 from Marshalling boxes in the powerhouse to demarcation boxes in the switchyard.
- Termination of P&C cabling for U1/2 in the Marshalling and demarcation boxes.

Outstanding work which will covered by the remaining amount of the Partial Release

- Pulling of U3/4 P&C cabling from the Marshalling boxes to demarcation boxes.
- Termination of U3/4 P&C cabling from the Marshalling boxes to demarcation boxes.
- Final grading, handrails and steps for the civil installation.

Contingency Funding from the Partial Release was used to cover the cost of the following: **$1.9M**

- Design and installation of the cable duct and vault in the switchyard. This risk was identified since the design was not available at the time of estimate and contingency funding was set aside to cover this risk.
- Cost of scaffolding for cable tray installation. The cable tray routing for power trays were not known at the time of estimate and contingency funding was set aside to cover this risk.
- Trench installation delays due to interferences and boulders during the boring under the security fence.
- Delays and rework due to the main service water break in the switchyard. The break was not a result of this project.

Full Release funding is required to complete the following work. **$7,452K**

- Increase in Hydro One commissioning cost for P711. Note Hydro One is responsible for installation costs related to the upgrade/replacement of their equipment.
- Increase in installation cost due to the ISTB project (double shifts / premium time for electrical contractor).
- Design for U3/4 execution during P841. TCD for this package is 28 Feb. 2008.
- Increase scope to include the U2/3 Safe Storage Alarm reduction into the execution Engineering Change Package.
- Increase scope to remove On Line Wiring covered under U2/3 Safe Storage packages
- Complete the commissioning for U1/2 during P711
- Start the detailed design for U3/4 and to complete the commissioning for U3/4 during P841
- Alarm cleanup for U1/2 during P911
- Alarm cleanup for U3/4 during P1041
- Close out

Explanation for increase ($1.2M) from the Partial Release

- Increase in commissioning cost during P711 outage
- Scope increase as some of the U2/3 Safe Storage scope (switchyard related) had to be brought into this project to eliminate re-work and ensure configuration management was maintained.
- Inter-Station-Transfer-Bus impact as double shifts and premium time were needed to recover the time lost by the trades used to support this work.
- Increase in security cost. 24/7 coverage were required during the boring and work next to the security fence.
- Increase in design costs to start the U3/4 detailed design for P841.
- Soil removal cost.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3	Alt 4	Alt 5
Revenue	(76,966)	(4,348)	(4,348)	(6,112)	(40,657)		
OM&A	(22,052)	(1,115)	(1,115)	(3,724)	(22,052)		
Capital	-	(14,052)	(6,637)	(7,041)	(905)		
NPV (after tax)	(28,492)	(14,972)	(8,793)	(11,198)	(19,544)		
Impact on Economic Value (IEV)	N/A	13,520	19,699	17,294	8,948		
IRR%	N/A	15.6%	27.4%	24.5%	41.2%		
Discounted Payback (Yrs)	N/A	11.20	7.33	9.25	4.00		

Status Quo - Not Recommended

This option is not recommended since it would not be possible to complete U1/2 installation, and the investment to date would be lost. Also, the existing temporary arrangement to bypass the damaged relay building equipment was intended to be a short term solution. This and the degradation of the existing cabling in the cable ducts connecting the OPG units to the relay building will not ensure proper protection & control of the PNGS-A units' grid connection and is not in compliance with the NPCC/IESO guidelines for grid protection.

Base on the cable fault history input from Performance Engineering, Hydro One and other stakeholders, it is predicted that the probability of a similar failure in the future is significantly high. Any such failure in the switchyard equipment will isolate both operating units (Units 1 and 4) from the transmission grid with substantial financial loss to OPG in the order of 500K$ per unit per day.

Hydro One is spending considerable resources and funding to upgrade reliability of the switchyard. To ensure full advantage of these upgrades is obtained, OPG must improve the reliability of the connection to these systems.

The project will be unable to complete the U1/2 installation & commissioning and the investment to date would be lost.

Alternative 1 - Full Copper Technology with New Cable Duct - Recommended

OPG will continue to design, install and commission an improved interface system for interconnectivity between Hydro One and OPG systems with the following features:

- Like-for-like replacement of protection and control functions to the extent practicable.
- Design, installation and commissioning of interface system based on all copper replacement.
- Replacement of existing copper cables which are degraded due to being submersed in water for long durations and end of life expectancy.
- Design and install a new dual buried duct system for routing the cables from switchyard to the station.
- Design and install the revised Alarm and SOER signals from the switchyard to the station.
- Design and install new dual independent AC feed from plant to the switchyard as required for the new Hydro One relay buildings.

Hydro One will replace the existing relay building equipment with a dual independent PCT system incorporating full separation in compliance with NPCC/IESO guidelines and interfacing based on copper technology.

This option is recommended since it is based on existing copper technology and like-for-like replacement of the functionality of the protection and control scheme. The new duct system will allow cable replacement and other major tasks outside the outage schedule without any risk of damage to the operating units.

Reliability of the Class IV Power system is enhanced consistent with Safety Analysis requirements and reduction of probability of forced outages due to equipment failures in the switchyard.

Alternative 2 - Delay Project - Not Recommended

Delaying this modification is not recommended since this will keep the PNGS-A units and equipment at a high risk of grid protection related forced outages. If grid protection & control is not updated the OGCC may not allow the generating units to be connected to the grid. Either scenario would result in a subsequent financial impact of ~ 500K$ per unit per day.

The rate of degradation of the existing cabling is unknown. Any cost savings to OPG by delaying would be offset by the increasing risk of forced outages. Additionally, OPG and Hydro One costs to defer due to remobilization and interest costs is estimated to be $2.2 M.

Alternative 3 – Complete U1/2 Work and Leave U3/4 As Is - Not Recommended

The old and the new switchyard relay buildings would need to be maintained and U3/4 reliability issues would still exist. In addition, if U3/4 work is not performed, OPG will not comply with the current market rules for the Bulk Electricity System, as set by the current NPCC/IESO guidelines.

Alternative 4 – Do more - Not Recommended

The recommended option has considered all necessary actions to take full advantage of the upgrade in the switchyard protection scheme by Hydro One and achieving optimal reliability from the switchyard functions.

Alternative 5 – - Not Recommended

None

4/ THE PROPOSAL

The following are the objectives and deliverables for this **Full Release BCS**:

- To complete commissioning of U1/2 with increased scope and ISTB impacts (see Section 2.0, Background).
- To complete the detailed engineering work including the On Line Wiring for the U3/4 cable cutting & termination and alarm cleanup.
- To complete the installation of the Unit 3/4 cabling from the demarcation to the marshalling boxes.
- To prepare detailed work plans, field installation packages and commissioning procedures for P841 work.
- To complete all installation and commissioning work for Unit 034 portion of the project during P841 outage.
- To complete the close out of U1/2 and U3/4 design packages
- Alarm cleanup for U1/2 during P911
- Alarm cleanup for U3/4 during P1041

5/ QUALITATIVE FACTORS

Replacement of switchyard PCT equipment and related interfacing equipment and cabling will increase reliability of the entire switchyard, enhance OPG unit and equipment protection in case of a grid failure and vice versa while complying NPCC/IESO guidelines for the protection scheme.

Class IV electrical power system reliability will be increased. The probability of unit trips and associated equipment stresses following unit trips will be reduced. Impairment of the protection systems' availability during fault situation due to cable failures would be minimized. This would result in avoiding potential catastrophic equipment failure causing extended outages and/or significant grid impact.

This reduced probability of transmission failure and enhanced protection of OPG plant equipment will have a positive financial impact for the rest of the expected plant life for Pickering A Units.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Since the U1/2 commissioning has not been completed there is limited Lessons Learned/OPEX information available for U3/4.	This might lead to higher level of engineering installation and commissioning cost	**High**	Rigorous planning and team work with stakeholders to identify any emergent abnormal situations that may arise. General contingency	**Medium**
Scope				
Discovery - Increase in scope	Increased costs and schedule impact	**Medium**	As most of physical installation is complete, risk is now limited to commissioning, documentation, and configuration management. General Contingency	**Low**
Schedule				
Inability to meet design Outage milestones for P841 due to the same resources working on P711.	Non compliance with N-PROC-MA-0013 & N-PROC-MA-0022	**Medium**	Design has committed to delivering the P841 design EC on Feburary 28, 2008 (Refer to SCR P-2007-16725).	**Low**
H1 commissioning longer than outage window	Increased costs Lost revenue	**High**	P711 outage Lessons Learned will be used to take required actions for P841	**Low**
				Low
Resources				
Insufficient OPG Design resources to support project..	Schedule delays	**Medium**	Contract out Project Design work to external design agency. Obtain commitment from OPG Project Design to support project.	**Low**

Limited Hydro One resources to support commissioning work during outage	Delay in outage schedule	**Medium**	Set up contracts with Hydro One in advance to ensure availability of their resources as per schedule.	**Low**
Limited OPG station support.	Delay in schedule of pre-reqs and outage.	**Medium**	Obtain commitment for OPG station support as per schedule.	**Low**
Technical				
Commission failure	Increase in outage schedule	**Medium**	Detailed commissioning work plan. Support on standby for outage troubleshooting	**Low**
Regulatory				
No regulatory approval required.		**N/A**		**Low**
Environmental				
There are no environmental risks.		**N/A**		**N/A**
Health & Safety				
Personal injury from working In vicinity of high voltage.	Potential serious personal injuries.	**High**	Proper pre job briefing, appropriate PPE and work protection.	**Low**
Investment				
No investment risk involved		**N/A**		**N/A**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jun 2010	Jan 2011	George Boyd

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	600V power supply to new ATS building in the switchyard	Not in service	600V power supply to new ATS building n service	Successful AFS	Performance Engineering
2.	Unit 1/2 new Switchyard protection and control cabling in service.	Not in service	U 1/2 new protection and control cabling in service	Successful AFS	Performance Engineering
3.	Unit 3/4 new switchyard protection and control cabling in service	Not in service	U 3/4 new protection and control cabling in service	Successful AFS	Performance Engineering
4.	Configuration documentation	Existing configuration	Revised Configuration	ECC Close Out	Project Design

Appendix "A" — Glossary (acronyms, codes, technical terms)

AFS	Available For Service
BCS	Business Case Summary
NPV	Net Present Value
PCRAF	Project Change Request Authorization Form
PEP	Project Execution Plan
MWH	Mega Watt Hour
NPCC	North-eastern Power Coordinating Council
IESO	Independent Electricity System Operator
OGCC	Ontario Grid Control Center
PIR	Post Implementation Review
PCT	Protection, Control & Telecom
PNGS	Pickering Nuclear Generating Station
OPG	Ontario Power Generation
CT	Current Transformer
PT	Potential Transformer
SER	Sequence Event Recorder

Appendix “B” Project Funding History

Release Type	Month	Year	2006	Cumulative Values 2007	2008	2009	2010	2011	2012	Later	Total
Partial	N/A	N/A	260	8,060	0	0	0	0	0	0	8,320
Full				1,125	3,350	1,867	841	269			7,452
None											0
None											0
N/A											0
N/A											0
N/A											0
N/A											0

LTD Spent	N/A		260	7,155							7,415

Comments:
2007 year to date values are up to the end of Fiscal week 093 in Scores.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:
2007-2011 labor rates are used.

Cost of material, support and vendor design are taken from the conceptual budgetary estimates received from vendors and other OPG groups.

Financial Assumptions:
7% discount rate.

Project / Station End of Life Assumptions:
End of life expectancy for Pickering A station assumed ≤ 2024.

Energy Price / Production Assumptions
Energy Price at $49.5 / MWH
Production assumed as 510 MW per unit for Pickering A units (1 & 4)
Capacity factor 0.8
Revenue loss per unit for one year = 510x0.8x24 (hours)x365 (days)x$49.5 = $176,916,960

Operating Cost Assumptions

N/A

Other Assumptions:
Considering the previous cable fault records, inputs from Hydro One and Performance Engineering, the probability of similar fault reoccurring in future is considerable and is an increasing function with time.

For our calculation a simple exponential distribution of risk ($Y= M e^{0.1659 t}$) is considered for the rest of plant life up to 2024 with a base risk (5%) at present as shown in figure 1.
Y= Cumulative risk probability, M= Base risk factor, t= Plant life from now (0-18 Years)

In case of a severe failure due to current condition in the Pickering A switchyard both the units (U1 & U4) will be disconnected from the grid for a minimum 60 days period before it can be restored per input from Hydro One.

Revenue loss for any such failure is calculated with cumulative risk factor derived from the exponential distribution for that time period and generation and OM&A cost for 60 days forced outage for two units.
Generation revenue loss for 60 days forced outage for 1 unit = $177/365X60 = $29M / unit
Since two units (Unit1& 4) are connected to the grid via the PNGA switchyard the effective generation loss due to unavailability of the switchyard to be considered as two times the calculation = $29MX2= $58M
OM & A manpower, material and engineering cost for 60days outage to restore 2 units back to the grid
= Manpower(60 X 200 K$) + Approx. Engineering & Material cost (4000K$) ~ $16M

Total economic impact for 60 days outage = 58+ 16 ~ $74M
Estimated economic impact = (Total economic impact) X Risk Probability at that time.

Assumed 1 year delay for the delay option (Alternative-2) with project cost escalation @ 3% per year of delay

Interest and remobilization costs are estimated at $2.2M

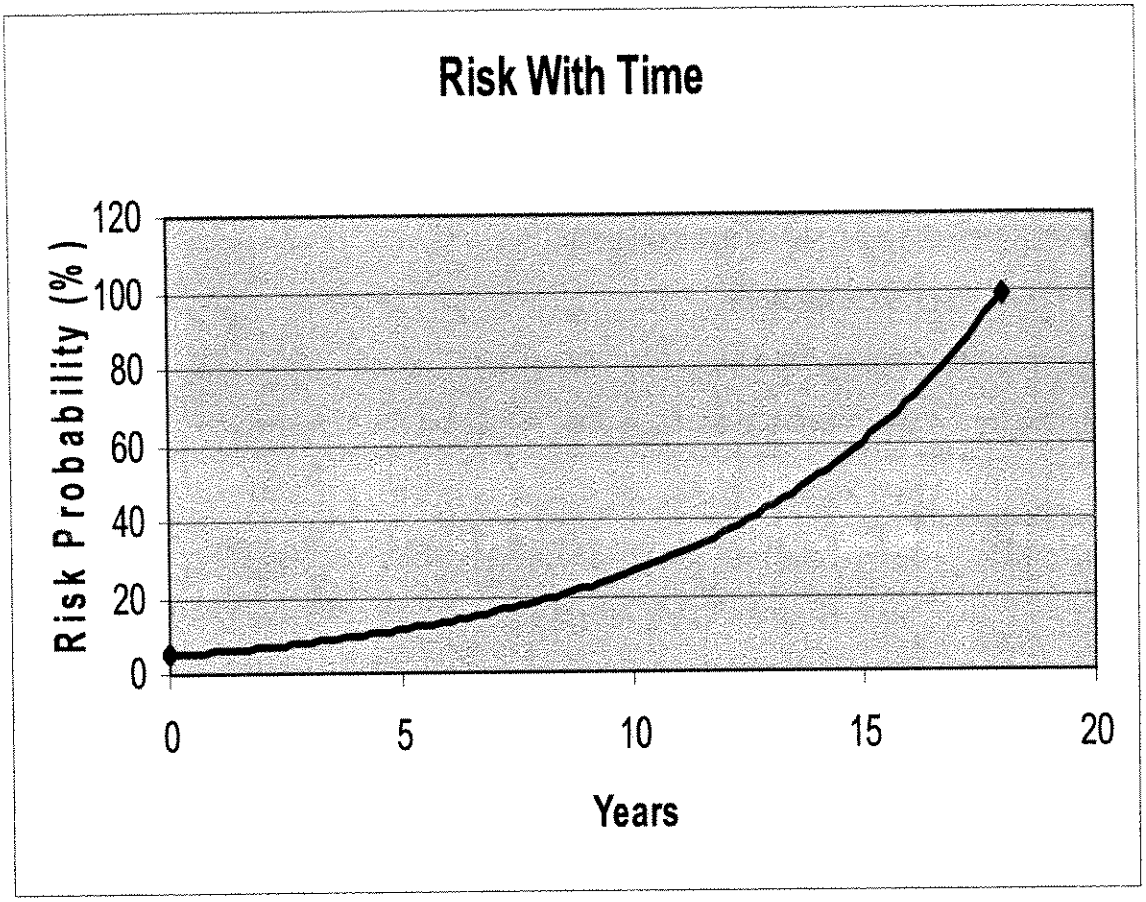

Risk With Time
Risk Probability (%)
120
100
80
60
40
20
0
0
5
10
15
20
Years

Figure - 1

PNGS-A Switchyard Relay Building Replacement Project 13 - 49266

Full Release Business Case Summary NA44-BCS-65130-00002-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Yr 2006	2007	This Release 2007	This Release 2008	This Release 2009	This Release 2010	This Release 2011	Later	Total
Project Management (OPG)	24	568		575	461	286	123		**2,037**
Engineering & Drafting (OPG)		583	231	426	340	259	49		**1,888**
Material		1,510	50	60	30	15	-		**1,665**
Installation – PWU, BTU	22	693	120	491	305	57	35		**1,723**
Contract - Design	78	550	164	100	100				**992**
Contract - Installation		2,220	300	720	110	-	-		**3,350**
Contract - Other									**-**
									-
									-
Interest (Capital Project Only)		180		205	90	30			**505**
Project Costs (excl contingency)	**124**	**6,304**	**865**	**2,577**	**1,436**	**647**	**207**	**-**	**12,160**
General Contingency		1,892	260	773	431	194	62	-	**3,612**
Specific Contingency									**-**
Project Costs (incl contingency)	**124**	**8,196**	**1,125**	**3,350**	**1,867**	**841**	**269**	**-**	**15,772**
2007-2011 Business Plan		6,215		2,577	1,286	647	207		**10,932**
Variance to Business Plan	**124**	**89**	**865**	**-**	**150**	**-**	**-**	**-**	**1,228**
Committed Cost									**-**
Inventory Write Off Required									**-**
Spare Parts / Inventory									**-**
Total Release (excl contingency)	**124**	**6,304**	**865**	**2,577**	**1,436**	**647**	**207**	**-**	**12,160**
Total Release (incl contingency)	**124**	**8,196**	**1,125**	**3,350**	**1,867**	**841**	**269**	**-**	**15,772**

Ongoing OM&A (non-project)									**-**
Removal Costs (incl in above)									**-**

Basis of Estimate

Design Complete	Up to - 40%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	N/A	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	No
Similar Projects	N/A	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Oct 2007.

Reviewed By: Oct 12/07

Craig Verwey
Project Manager

Approved By:

Peter Floyd
Eng & Mods Manager (Strat IV)

PNGS-A Switchyard Relay Building Replacement Project 13 - 49266

Full Release Business Case Summary NA44-BCS-65130-00002-R000

Attachment "B" **Project Variance Analysis**

Choose One	LTD Sep 2007	Full Release Last BCS N/A N/A	Full Release This BCS N/A N/A	Variance	Comments
Project Management (OPG)	594	2,109	2,109	-	No Change
Engineering & Drafting (OPG)	742	1,697	1,928	231	Additional amounts for On Line Wiring and scop increase for station initiative for Alarm reduction.
Material	1,320	1,615	1,665	50	Increase in cable cost
Installation – PWU, BTU	619	1,545	1,765	220	Security costs, cost for soil removal
Contract - Design	415	700	914	214	Cost for cable vault design
Contract - Installation	3,661	2,946	3,246	300	Double shifts / premium hours due to ISTB impa Installation of cable vault.
Contract - Other				-	
				-	
				-	
Interest (Capital Project Only)	64	505	505	-	
Project Costs (excl contingency)	**7,415**	**11,117**	**12,132**	**1,015**	
General Contingency		**3,335**	**3,640**	305	
Specific Contingency				-	
Project Costs (incl contingency)	**7,415**	**14,452**	**15,772**	**1,320**	
Committed Cost				-	
Inventory Write Off Required				-	
Spare Parts / Inventory				-	
Total Release (incl contingency)	**7,415**	**14,452**	**15,772**	**1,320**	
Total Release (excl contingency)	**7,415**	**11,117**	**12,132**	**1,015**	

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

Life to Date for the project is based on 2006 and 2007 year to date values up to Fiscal Week 093 in SCORES.

\ttachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
30	Oct.	2007	Full Release BCS approved
16	Oct	2007	P711 outage pre req. complete.
28	Dec.	2007	U1/U2 PCT system commissioning complete and AFS'd.
28	Feb.	2008	P841 Detailed Design complete
12	Jun.	2008	Close out for U1/U2 PCT.
11	Aug.	2008	Pre req. work for P841 complete.
10	Dec.	2008	U3/U4 PCT commissioning complete and AFS'd.
10	Jun.	2009	Close out for U3/U4.
16	Nov.	2009	Alarm clean up for U1/U2 by P911 and AFS'd.
15	Jun.	2010	Alarm clean up for U3/U4 by P1041 and Final AFS.
15	Dec.	2010	Project close out complete.

A Project Execution Plan (PEP) will be approved by Jan 2008

Comments: Major installation and commissioning activities of this project are outage dependant and currently scheduled for P711 in 2007 and P841 in 2008.

C

Pickering B Emergency Power Generator Control UpgradeProject 13 - 49110

Full Release (Phase 1) Business Case Summary NK30-BCS-54800-00009-R000

1/ RECOMMENDATION:

We recommend approval of a Phase I release of $ 8.6M Capital to complete Detailed Engineering, procure PLC based engineered materials for both EPGs and installation / commissioning of control system on first EPG.

The Business Objectives of this project are:

- Eliminate the possibility of a unit forced outage caused by the increasing failure of obsolete, twenty-five year old EPG control systems that have a limited supply of spare parts due to Original Equipment Manufacturer non-support. Coincidental failure of both EPGs will lead to the shutdown of all Pickering A and B units if the system impairment is not resolved by repairing one of the units within 24 hours.
- Improve EPG availability.
- Remove EPG Control system as a negative contributor to Emergency Power Generator System Health.

EPG performance for 2006/2007 was within the start reliability target (98%) but failed to meet the availability target of 95%. Moreover, availability performance is trending downwards. Based on 2002-2006 station data the Emergency Power System exceeded the Predicted Future Unavailability Target as specified in Pickering B Reactor Safety Reliability Program (SCR P-2007-07874). The dominant contributor to this result was start failures of EPGs and these were mostly due to control system problems. The Sponsor is concerned that continuous degradation of the control system will lead to forced station outages.

There have been 13 functional failure events where an EPG tripped during routine testing since 2000. Although, in each case, corrective actions undertaken per the Abnormal Incidence Manual were successful in replacing/repairing failed components, there is no guarantee this effort can be sustained in the future due to lack of parts.

$000's (Incl contingency)	Funding	LTD 2007	2008	2009	2010	2011	2012	Later	Total
Currently Released	Developmental	895							895
Requested Now	Full - Phase 1	(255)	2,058	5,612	1,229				8,644
Future Funding Req'd	Full - Phase 2			156	2,605				2,761
Total Project Costs		640	2,058	5,768	3,834	-	-	-	12,300
Other Costs									-
Ongoing Costs									-
Grand Total		640	2,058	5,768	3,834	-	-	-	12,300
Investment Type Sustaining		Class Capital		(IEV) Impact on Ec Value 3,765		IRR N/A		Discounted Payback N/A	

Submitted By:

Nov 29/07

Pierre Tremblay
Senior Site Vice President, Pickering B

Date:

Finance Approval:

Dec 4, 2007

Jim Beech
Vice President Nuclear Finance

Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

6 Dec 07

Tom Mitchell
Chief Nuclear Officer

Date:

2/ BACKGROUND & ISSUES

System / Impact

The Emergency Power Generator (EPG) is an independent, seismically qualified source of electrical power to the Group II systems for the Pickering reactors after a loss of Class IV/III power due to a design basis event. The EPG system is an essential safety related system that allows the safe shutdown of the units when station power is not available. A significant, coincidental failure of both EPGs will result in a system impairment, not meeting design intent", until at least one could be repaired. This impairment could bring about the forced outage of all the Pickering A and B units. Pickering Units, both A and B, can not operate without the EPG/EPS systems being available.

To date shutdown of the Pickering units has not been required due to EPG impairments.

Performance Status

The Emergency Power Generator (EPG) controls are obsolete. Original parts are no longer in production; spare parts are extremely limited and not supported by the Original Equipment Manufacturer (OEM), making any significant failure of the control system probably irreparable. Additionally the electronics of the control system are beginning to show age related failures and they have become increasingly unreliable resulting in reduced EPG system availability. The useful reliable life left in the control system is coming to an end.

The systems have a requirement of 98% start reliability at a 75% confidence level and a 95% system availability. The EPG's can only be unavailable for a few weeks before the system unavailability target is not met. Since some unavailability is attributed to planned maintenance, there is little allowance for forced outages before target availability requirements are not met. Even one start failure per quarter can significantly reduce the system performance.

Per 2006 Pickering B Annual Reliability Report NK30-REP-09051.1-00006 (SCR P-2007-07874), based on 2002-2006 station data, the Emergency Power System exceeded the Predicted Future Unavailability Target as specified in Pickering B Reactor Safety Reliability Program (NK30-INS-03611-00001). The dominant contributor to this result was start failures of EPGs and these were mostly due to control problems.

From the historical data on engine performance (see Attachment D), the start reliability performance is steady. However system availability is slowly declining due to increased failures over the last 4-5 years involving the control system (e.g. Governor, vibration monitoring). In the last quarter the availability target was not met. The system availability is expected to trend significantly below target without extensive corrective action. Continued degradation increases the threat of a multi unit generation threat when two EPGs become unavailable.

The following functional failure events have taken place since 2000 due to EPG controls aging:

- Sep 2000 (P-2000-06128: Failure of EPG2 during M-1 test)
- August 2001 (P-2001-08001: Trip of EPG2 start up for test M-8 on Unit 6)
- August 2001 (P-2001-08551: 058-54800-EPG2 High vibration trip on start up)
- October 2001(P-2001-10253: Emergency Power Generator 2 trip on high vibration)
- April 2002 (P-2002-04503: 058-54800-EPG2 Failed during M-2 test run, Total loss of redundancy for EPS)
- 3rd quarter 2002, EPG2 control board failure on air intake filter cleaning control system
- August 2003 (P-2003-12657: EPG declared unavailable, back-up overspeed switch failure)
- August 2004 (P-2004-14255: Failure of Backup overspeed module)
- August 2005 (P-2005-12259: Unavailable due to Backup Overspeed Relay Failure)
- October 2005 (P-2005-16974: Failed to start, relay failure)
- January 2006 (P-2006-00981: failed during test run. L3 impairment on total loss of EPS redundancy)
- October 2006 (P-2006-18479: EPG2 Speed switch failure during M-002 test)
- May 2007 (P-2007-12186; EPG2 tripped on overspeed during M-001 test))

In the events above, the EPG tripped during a routine start test due to EPG control system material degradation and the EPG was declared unavailable. Defective components (vibration monitoring cable/transducers/filters etc.) were replaced/repaired, EPGs were tested and system declared available.
A critical spares list has been compiled by Performance Engineering but most of the parts, due to their age, are no longer being produced by the OEM. When components fail it requires Maintenance, Performance Engineering, Design and Procurement Engineering departments' involvement to find a workable solution. In the past the OEM has helped in locating obsolete parts through their contacts; however, these parts are left over stock from earlier years and will no longer be available when stocks are depleted. This leaves the machines in a vulnerable state.

The SCRs in Attachment E document some of the control component failures that have taken place since 2000.

OPEX

Darlington Nuclear Generating Station also experienced similar degradations in system availability due to EPG control aging in 1999 (same OEM) and subsequently completed implementation of EPG controls replacement (Project # 33249) in 2004.
Similar upgrades to the Pickering B Standby Generator Governors/Control system are in progress under Project 13-49109.
Lennox Generating Station completed an upgrade of the control system for their similar generators (same OEM) in 2006/07.
All of these projects were reviewed and resulting information was incorporated into the total project cost estimate. Lessons learned to-date will also be incorporated into risk management strategies with particular emphasis on the contract for engineered materials and software procedures.

Scope Challenge

During the Preliminary Engineering phase the unavailability of spare/substitute parts and required scope was validated.

Project Expectations

The proposed "Pickering B EPG control upgrade 13-49110" is supported by the Pickering B Forced Loss Rate (FLR) Report NK30-REP-09200-00005 "Forced Loss Rate Projections Pickering B 2005 to 2009" under Section 4.4 "Key supporting projects to mitigate FLR". Per section 4.3 of the FLR report, EPG controls have been identified as potential unit generation threats that will increase number and length of forced unit outages due to deteriorating material conditions. Implementation of this project will remove this threat.
The System Health status indicator will be one of the measures of the effectiveness of this project. The EPG overall colour rating of YELLOW is attributed to the history associated with the functional failures on aging parts that are obsolete and no longer supported by the OEM. Per July 2, 2007 System Health Review the System Health is trending downward towards RED based on continual degradation of control system components.
A significant reduction in maintenance and engineering costs is expected due to reduction in forced EPG outages as a result of completion of this modification.

Other considerations

An EPG Outage is required to install the EPG Control System. Installation on the second EPG will be staggered six months after the first installation to resolve any latent technical issues arising from the first installation.

During the field installation, only one EPG will be available for service; if it should fail all Pickering units may have to be shutdown if it cannot be repaired with 24 hours. Therefore as part of the Preliminary Engineering for this project, an assessment of alternatives to maintain reliability during the field installation of the retrofit has been completed.
Based on OPEX from SG Governor Project 13-49109 an extended EPG outage of up to 56 days may be required for installation and commissioning. Through use of OEM experienced installation/commissioning personnel in combination with OPG resources it is expected that this time frame can be reduced for the EPGs.
In addition to maintaining the outage window as short as possible, steps will be taken to ensure maximum reliability

of the other EPG prior to starting the installation outage. A specific contingency has been included for use of a backup source of generation if justified. Final decision on use of this contingency will be made in consultation with Station personnel including Reactor Safety.

All estimates for commissioning assume that a load bank is available to support commissioning testing. Installation of the Load Bank modification (not part of this project) to allow use of a load bank is in progress and expected to be completed in 1st Quarter 2008.

Current Status of Project

Under the Developmental release Preliminary Engineering has been completed. This included a review of all control components and possible options for the upgrade of each. Based on this review Design Requirements and Technical Specifications have been issued. Approval for Sole Source justification for the OEM has been obtained and a proposal received. In addition the options for maintaining system reliability during the field installation of the retrofit were assessed. Phase I budgetary cost has been developed in conjunction with a third-party consulting firm, and a Level 1 schedule prepared for design, procurement and installations planned for 2009/2010.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Stop the Project	Alt 1 (Recommended) Install PLC Controls		Alt 2	Alt 3	Alt 4	Alt 5	Alt 6
		Full Cost	Incremental Cost	Delay 2 Years	Repl Parts for all aging Parts	Repl Parts for targeted Parts	New EPG	Alternate Generation Source
Revenue	-							
OM&A	(38,192)	(10,037)	(10,037)	(17,991)	(10,037)	(16,103)	(10,037)	(37,934)
Capital	-	(11,930)	(11,314)	(11,314)	(12,461)	(10,053)	(33,052)	
NPV (after tax)	(17,183)	(13,908)	(13,419)	(16,309)	(14,343)	(15,007)	(27,812)	(16,677)
Impact on Economic Value (IEV)	N/A	3,275	3,764	874	2,840	2,176	(10,629)	506
IRR%	N/A							

Stop the Project - Not Recommended

This alternative is not recommended because:

- Control system components are aging and have a history of failure.
- Components are obsolete and spares inventory is extremely limited and not supported by the Original Equipment Manufacturer.
- EPG reliability is threatened. Loss of one EPG control system does not directly affect station operation. However, if the second EPG becomes unavailable due to functional failure of the control system, it will result in the Emergency Power System being unavailable and a possible forced outage of all Pickering A and B units if not restored within 24 hrs.
- EPG System Health is trending toward Red due to control issues.

Alternative 1 - PLC based Controls Upgrade - Recommended

We recommend approval of a Phase I release of $ 8,644K Capital to complete Detailed Engineering, procure PLC based engineered materials for both EPGs and installation / commissioning of control system on first EPG.

This is the ***Recommended Alternative*** because:

- It satisfies the Business Objectives
  - Eliminate the possibility of a unit forced outage caused by the increasing failure of obsolete, twenty-five year old EPG control systems that have a limited supply of spare parts due to Original Equipment Manufacturer non support. Coincidental failure of both EPGs will lead to the shutdown of all Pickering A and B units if the "system impairment" is not resolved by repairing one of the units within 24 hours.
  - Improve EPG Availability
  - Remove EPG Control system as a negative contributor to Emergency Power Generator System Health
- Provides the greatest financial benefit.
- Reduce maintenance/engineering costs associated with extended forced outages of EPG due to lack of parts.
- Will provide continued OEM technical and parts support for control system since system is upgraded to current technology.

The breakeven point for this investment is reached when the probability of a 6 unit forced outage of 30 days reaches 2.0 % per year. Based on past EPG performance, it is reasonable to assume that we would likely surpass this level of risk should the investment not be made.

Alternative 2 - Delay Project - Not Recommended
Delay 2 years
This alternative is not recommended because:

- Any delay increases the Corporate exposure to costly unit and EPG forced outages.
- Reduces the financial benefit.
- Delays the improvement to EPG System Health.

Alternative 3 – Install Replacement Components on All Aging Components - Not Recommended

Specify, procure and install replacement components on a part by part basis to replace all aging control components.

Although this alternative would largely satisfy the Business Objectives, it is not recommended because:

- It is not cost effective.
- Since analog technology is generally no longer supported in the industry for this type of application replacement of most obsolete parts would need to be done on a custom basis. Replacement can be achieved by a combination of non-identical analog component modifications, reverse engineering of analog components and modifications to upgrade to digital based components. This is essentially what the station has been trying to do for the last few years with limited success.
- Labour commitment to achieve this alternative is significant as each of more than 60 unique components (125 components total) would have to be Engineered, Procured and Installed.
- Functional integration of parts replaced in this way carries a significant risk, due to use of different vendors and difficulty of testing certain components prior to installation.
- This alternative does not cover replacement of skid or panel wiring, which are also aging, therefore the gain in reliability/availability is not equal to the recommended case.
- Risk still exists for further obsolescence of analog replacement parts that cannot be fully addressed by purchase of spares.
- Risk associated with continued support by OEM for entire EPG if control system replaced part by part with non-OEM components.

Alternative 4 – Install Replacement Components on Target Aging Components - Not Recommended

Specify and procure replacement components for all aging control components on a part by part basis. Install only the replacement parts for failing critical components (Governor, vibration monitoring, some relays). Remaining components to be replaced as required by station.

Although this alternative would satisfy the Business Objectives, it is not recommended because:

- It is not cost effective.
- Since analog technology is generally no longer supported in the industry for this type of application, replacement of most obsolete parts would need to be done on a custom basis. Replacement can be achieved by a combination of non-identical analog component modifications, reverse engineering of analog components and modifications to upgrade to digital based components. This is essentially what the station has been trying to do for the last few years with limited success.
- Labour commitment to achieve this alternative is significant as each of more than 60 unique components (125 components total) would have to be Engineered and Procured.
- Functional integration of parts replaced in this way carries a significant risk, due to use of different vendors and difficulty of testing certain components prior to installation. Since not all parts are to be installed a further risk of discovery issues with regard to fit and function may emerge when they are installed at a later date.
- This alternative does not cover replacement of skid or panel wiring which also are aging therefore the gain in reliability/availability is not equal to the recommended case.
- Risk still exists for further obsolescence of analog replacement parts that cannot be fully addressed by

purchase of spares.

- Risk associated with continued support by OEM for entire EPG if control system replaced part by part with non-OEM components.

Alternative 5 – Replace entire EPG with new - Not Recommended

Although replacement of the entire EPG would satisfy the Business Objectives, it is not recommended because:

- It is not cost effective.
- This alternative is more than is required to meet long term reliability of the EPGs. A Component Condition Assessment has been completed for this system and it recommended only replacement of the gas turbine and fuel pumps for Life Extension. The Control system was not part of the assessment since it was assumed that this project would be implemented.

Alternative 6 – Alternate Generation Source – Not recommended

Rent and tie-in alternate generation source to support reliability of EPGs. The EPGs would continue to operate as the main power supply for the mission.

This alternative is not recommended because:

- It does not fully support the business objectives because it is not an equivalent source of power for the Group II systems in the event of a seismic event.
- Ongoing issues of maintenance burden and obsolete parts for the EPGs will continue.

4/ THE PROPOSAL

We propose approval of a Phase I release of $ 8,644K Capital to complete the Detailed Engineering, Procurement of Engineered Materials for both EPGs and Installation of the First EPG for the upgrade of the control systems for the two 2.5 MW Pickering Emergency Power Generators. This seismically qualified control system retrofit would include system control logic and instrumentation including new fuel control valve, new control panel, new control modules, new data logger, new programmable logic controller (PLC), new sensor systems, replacement of relays and field end devices.

Phase I major project deliverables are:

Project Execution Plan
Detailed Engineering – Issue of both Design Packages
Design Studies and Calculations (reliability report)
Procurement of materials, including spare parts and associated manufacturer's manuals (for Both EPGs)
Software categorization and qualification.
Workplans and Field Engineering Packages (1st EPG)
Installation and Commissioning (1st EPG)
Training for Operations, Maintenance, and Performance Engineering staff on new systems.
New and/or revised Operating and Maintenance Procedures
Lessons Learned from 1st installation/commissioning

Phase II major project deliverables are:
Updated Project Execution Plan
Incorporation of Lessons Learned into both EPGs
Revised Design Packages as required
Workplans and Field Engineering Packages (2nd EPG)
Installation and Commissioning (2nd EPG)
Design and Project Closeout
Post Implementation Review, Lessons Learned.

5/ QUALITATIVE FACTORS

Lower system maintenance costs.
Improved diagnostic capabilities on EPG using data logger and monitor, thus decreasing EPG forced outage troubleshooting times.
Elective and Corrective Maintenance backlogs expected to decrease due to replacement of instrumentation and components.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Underestimation of Design costs	Higher cost impact if design becomes more complex than anticipated	Medium	Ongoing OPEX review of similar projects (13-49109 Pickering B Standby Generator Governor Upgrade and 10-33249 Darlington EPG Controls Replacement, Lennox GS EPG Controls Upgrade) will continue to mitigate cost risk. Multiple field walkdowns and COMS will be performed to avoid discovery issues later in design process.	Low
Release quality cost estimate not available until first installation complete	Increased costs.	Medium	Overall 30% contingency, Vendor quote available.	Low
Scope				
Scope Expansion	Delay and increased costs.	Medium	1) Project charter has been completed by Performance Engineering (customer) identifying the scope of this project. 2) Vendor proposal in hand detailing scope, all stakeholders were involved during discussion of proposal.	Low
Field Discovery issues that may impact on modification	Delay, potential increased costs	Low	Time will be incorporated into installation schedule to allow for some discovery work.	Low
The EPG Full load test Project is not completed prior to this project's need date.	Delay and increased costs,	Low	Monitor progress of Full Load Project, raise priority of work if load testing equipment is not on track for completion prior to required commissioning date for this project	Low
Schedule				
EPG outage schedule is driven by station priorities	Installation will be delayed, IOP milestone process may not be followed, increased costs.	Medium	Integrate project work into station EPG/SG outage schedule and EPG maintenance work program early in project planning. Integrate scheduling OPEX for previous SG	Low

			projects.	
Delay of Detailed Design	Installation will be delayed, increased costs	**Medium**	Based on OPEX from SG Governor project 13-49109 the design strategy will be to avoid customization of vendor product unless change is critical. Customization of vendor drawings and manuals to OPG specifics and nomenclature will be done by OPG not the vendor. SQA gaps are known and strategy in place to close gaps. Design schedule has incorporated contingency for handoffs and design resource contraints.	**Low**
Vendor Material availability	Installation will be delayed.	**Medium**	Although vendor proposal has been received, firm commitment to delivery date will not be confirmed until award of PO. Prompt resolution of PO terms and conditions is required to maintain schedule.	**Low**
Resources				
Lack of experienced engineering support resources for this Phase of the project	Delay in completion.	**Medium**	Appropriate engineering resources both OPG (Project Design, SQA and HFE support) and contract have been committed. Consideration has been given in the schedule to impact on resources from other similar projects (SG Governor Project 13-49109).	**Low**
Limited installation resources (BTU / PWU). Competing with other projects or maintenance programs. Limited Ops resources to support commissioning	Delay in completion	**Medium**	Use contract resources if necessary, integrate vendor field installation/commissioning support into resource plan. Permit walkdown prior to outage.	**Low**
Technical				
Modifications do not meet the design intent and/or requirements. Intregration of control upgrade with existing EPG systems.	Modification would require significant re design /re-work. Delay, extended commissioning /increased costs	**Medium**	Design will be validated through extensive review process and rigorous COMS review by stakeholders OEM is the vendor of choice to ensure good integration. Sole Source justifiction for OEM has been approved.	**Low**

			Vendor will witness full load operation of EPG prior to finalizing design to ensure specific operating characteristics of Pickering EPGs is incorporated. Vendor will complete FAT and integration testing with the specific Pickering EPG configuration prior to acceptance by OPG. Proven vendor design will be used unless it cannot meet critical OPG parameters..	
Unforeseen issues in Software Qualification process. Possible software modifications during commissioning.	Delay /increased costs	**Medium**	Review of Vendor processes has been completed at Vendor site by OPG SQA experts. Gaps in vendor process are well understood and strategy is in place to close gaps. Funding to address this has been included in estimate. Design will consider possibility of field changes to software and will set tuning ranges accordingly. Field change process will be in place.	**Low**
Unforseen Human Factors Engineering (HFE) issues	Delay/increased costs	**Medium**	Engaged HFE early in preliminary design. Utilize OPEX from Lennox and Darlington EPG Controls upgrades completed by same vendor.	**Low**
Regulatory				
CNSC review required for installation strategy.	Scope changes as a result of CNSC input.	**Low**	Review of OPEX from a similar installation at Darlington indicated that a temporary backup generation source for the EPG function may be required during installation of the upgrade on both EPGs. The project will assess use of other means such as minimizing the length of installation window, enhancing reliability of available EPG during installation window as an alternate to the temporary generator. However a Special contingency has been included for the temporary generator if required. Issue will be reviewed with CNSC as early as possible.	**Low**
If required, temporary backup generation source for the EPG	Rework of installation strategy, delay to schedule	**Medium**	Identify need for contingency early in schedule.	**Low**

function cannot be seismically qualified.				
Environmental				
Scrapping of removed equipment	Environmental Regulatory non-compliance.	**Low**	Material to be surveyed and scrapped in accordance with approved procudures.	**Low**
Health & Safety				
Accident / Injury	Personel injury and Delay to work	**Low**	COMS performed to ensure all risks identified. Compliance with all approved procedures. Specific risks to be highlighted in workplans.	**Low**
Investment				
The recommended alternative does not meet the Business Objective	Loss of Sunk cost. Risk of forced outage continues. System Health attributable to control system issues does not improved	**Low**	Digital control upgrade is a proven technical package that has successfully installed in numerous applications.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jun 2010	Jan 2012	Manager Performance Engineering

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Emergency Power Generator (EPG) System Health performance indicators	System Health - YELLOW at time of BCS approval	Removal of EPG Control systems as a negative contributor to system status	Updated System Health Report indicating imporved status for EPG Controls systems.	Performance Engineering / System Engineer
2.	EPG meets expected performance criteria and reliability	N/A	Commissioning Results accepted by Design	Signed Commissioning Report in PASSPORT	Design Projects / Project Manager
3.	System Availability	93% average	95% system availability	System Health Report	Performance Engineering / System Engineer
4.	Reliability rate	98%	The systems have a requirement of 98% start reliability at a 75% confidence level	System Health Report	Performance Engineering / System Engineer
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

AFS Available for Service
BCS Business Case Summary
BP Business Plan
BTU Builders Trade Union
CNSC Canadian Nuclear Safety Commission
COMS Constructability, Operability, Maintainability, Safety
CUSW Direct Hire Building Trade Union (Electrical)
CWP's Comprehensive Work Packages
DCN Design Change Notice
ECC Engineering Change Control
ECR Engineering Change Request
EPG Emergency Power Generator
FAT Factory Acceptance Test
FE Field Engineering
FIPR Field Installation Package Release
FME Foreign Material Exclusion
HFE Human Factors Engineering
IOP Integrated Operating Plan
ITP Inspection and Test Plan
I&C Instrument and Controls
IRR Internal Rate of Return
kWH Kilo Watt Hour
MWH Mega Watt Hour
NUCORDS Nuclear Components Reliability Data System
NPV Net Present Value
OAR Organizational Authority Register
OEM Original Equipment Manufacturer
OLW On line Wiring
OPEX Operating Experience
OPS Operations
O/T Overtime
PEP Project Execution Plan
PIR Post Implementation Review
PFU Predicted Unavailability Factor
PLC Programmable Logic control
PSL Power Supply List
PWU Power Workers Union
QA Quality Assurance
QCIV Quality Control Inspection Verification
QSITP Quality Surveillance Inspection Test Plan
SCR Site Condition Report
SE System Engineer
SG Standby Generator
SMB Site Management Board
SQA Software Qualification Assurance
TSSA Technical Safety Standards Authority

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:
Cost estimates have been validated by 3rd party reviewer. Task Identification sheets have been validated by all contributing resource groups. OPEX from similar projects has been incorporated into estimates.

Financial Assumptions:

Loss of revenue during forced unit outages:
(516MW for PB) x (85% Capacity Factor) x (24 Hours) x (30 days) x (Rate MWH) x (4 units)
(513MW for PA) x (85% Capacity Factor) x (24 Hours) x (30 days) x (Rate MWH) x (2 units)

Probability of 6 unit shutdown is 3.5%. This probability was assumed to increase each year by 3% of the prior year to EOL.

Repair Costs during forced EPG outages:
Length of EPG outages assumed 30 days
Maintenance resources: 5 persons x 8 hrs x 30 days unplanned outage x 2 EPGs
Engineering Resource: 2 person x 7 hrs x 30 days unplanned outage x 2 EPGs
Operating Resource: 2 person x 8 hrs x 10 days
Assume incremental cost is due to overtime charges only (20% of above).
Projected Increase (Escalation expense) = 3% per annum on the repair costs

Project / Station End of Life Assumptions:
Pickering B End of Life : 2014 Units 5,6 and 7 2016 Unit 8

Pickering A – 2019

Energy Price / Production Assumptions:

2007 49.5
2008 49.5
2009-2016 escalate at 2% per annum

Operating Cost Assumptions:

Other Assumptions:

ONTARIO POWER GENERATION

OPG Confidential	Page: 18 of 22
BUSINESS CASE SUMMARY	

Project Name 13 - 49110

Full Release (Phase 1) Business Case Summary NK30-BCS-54800-00009-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2006	Actual YTD Aug 2007	Previous Release 2007	This Release 2008	This Release 2009	This Release 2010	Future Release 2009	Future Release 2010	Total
Project Management (OPG)	106	194	78	343	349			336	1,406
Engineering & Drafting (OPG)	48	30	42	751	398	145		168	1,582
Material					750	750			1,500
Installation – PWU, BTU					1,555		121	1,329	3,005
Contract - Design	30	25	27	109	[redacted]				
Contract - Installation					[redacted]				
Contract - Other		36		25	[redacted]				
									-
									-
Interest (Capital Project Only)	4	11	9	75	185			86	370
Project Costs (excl contingency)	**188**	**296**	**156**	**1,303**	[redacted]				
General Contingency				390	[redacted]				
Specific Contingency				365	[redacted]				
Project Costs (incl contingency)	**188**	**296**	**156**	**2,058**	**5,612**	**1,229**	**156**	**2,605**	**12,300**
2007-2011 Business Plan	188		1,152	2,051	6,934		1,039		11,364
Variance to Business Plan	**-**	**296**	**(996)**	**(748)**	**(3,359)**	**895**	**(918)**	**2,005**	**(2,825)**
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	**188**	**296**	**156**	**1,303**	[redacted]				
Total Release (incl contingency)	**188**	**296**	**156**	**2,058**	**5,612**	**1,229**	**156**	**2,605**	**12,300**
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	Up to ~ 15%		Quality of Estimate	Budget + 30% to - 15%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	No
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Dec 2007.

Reviewed By:

George Makdessi
Project Manager

8 Nov / 07
Date:

Approved By:

Randy Ludlow
Eng & Mods Manager (Strat IV)

15 NOV 2007
Date:

Pickering B Emergency Power Generator Control Upgrade 13 - 49110

Full Release (Phase 1) Business Case Summary NK30-BCS-54800-00009-R000

Attachment "B" **Project Variance Analysis**

Capital	LTD Aug 2007	Total Project: Last BCS Mar 2006	Total Project: This BCS Dec 2007	Variance	Comments
Project Management (OPG)	300	1732	1406	-326	Reallocated resources to installation tasks
Engineering & Drafting (OPG)	78	2241	1582	-659	Some Design resources to be contracted, reduced Design estimate based on OEM information
Material		3990	1500	-2490	Reduced based on OEM vendor proposal.
Installation – PWU, BTU		3153	3005	-148	Resources reallocated from PM and to Contract Installation
Contract - Design	55	[redacted]			Resources reallocated from OPG Engineering
Contract - Installation		[redacted]			Resources reallocated from BTU/PWU installation
Contract - Other	36	[redacted]			Cost of 3rd party estimation service higher than estimated
				0	
				0	
Interest (Capital Project Only)	15	486	370	-116	
Project Costs (excl contingency)	**484**	[redacted]			
General Contingency		[redacted]			
Specific Contingency		[redacted]			Added to address installation reliability
Project Costs (incl contingency)	**484**	**14390**	**12300**	**-2090**	
Committed Cost					
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**484**	**14390**	**12300**	**-2090**	
Total Release (excl contingency)	**484**	[redacted]			

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

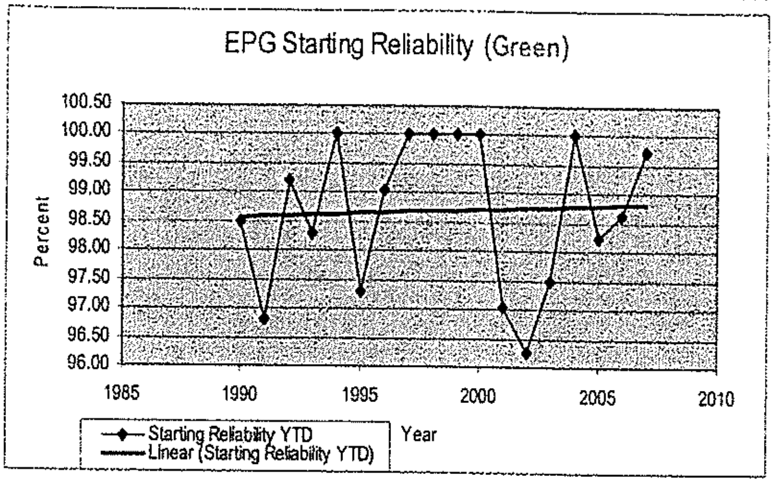
Attachment "C" **Key Milestones**

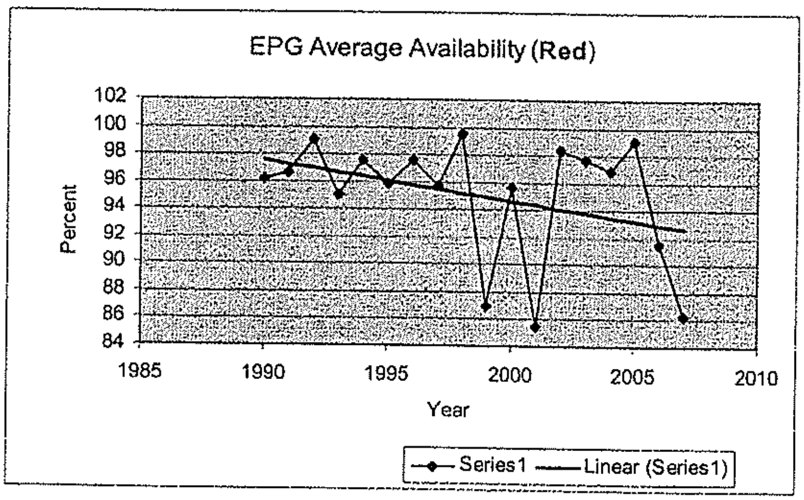
Completion Date			Description
Day	Mth	Yr	
14	March	2008	Material Contract Award
02	April	2009	Detailed Design Package for 1st EPG Issued
17	Nov	2009	Detailed Design Package for 2nd EPG Issued
1	Oct	2009	Installation start 1st EPG (T-0)
18	Nov	2009	AFS 1st EPG
30	Nov	2009	Lessons Learned review for 1st EPG
2	Nov	2009	Phase II Release
18	May	2010	Installation/start 2nd EPG (T-0)
29	Jun	2010	AFS 2nd EPG
19	May	2010	Complete Closeout 1st EPG
28	Dec	2010	Complete Closeout 2nd EPG
14	Jan	2011	Project Complete

A Project Execution Plan (PEP) will be approved by Jan 2008

Comments:

Attachment D **EPG Reliability / Availability**





Attachment E SCR Summary

Event Date	SCR	Equipment / Event Summary
Sept 2000	P-2000-06128	Failure of 058-54800-EPG2 during M-1 test
May 2001	P-2001-04551	EPG spare governor modules unavailable
Aug 2001	P-2001-08001	Trip of 058-54800-EPG2 start up for test M-8 on Unit 6
Aug 2001	P-2001-08551	058-54800-EPG2 High vibration trip on start up)
Oct 2001	P-2001-10253	058-54800-EPG2 trip on high vibration
Oct 2002	P-2002-03171	Defective equipment relay KT220 from stores, no extra in stock.
Apr 2002	P-2002-04310	Failure of an EPG1 Vibration monitor channel
Apr 2002	P-2002-04503	058-54800-EPG2 Failed during M-2 test run, Total loss of redundancy for EPS
Aug 2003	P-2003-12657	EPG declared unavailable –backup overspeed module
Dec 2003	P-2003-20812	058-54800-EPG2 fails to start
Jan 2004	P-2004-01162	058-54800-EPG 1 Temp monitor spares unavailable
Jan 2004	P-2004-01239	058-54800-EPG1 Governor response
Jan 2004	P-2004-01658	Circuit boards not matching OEM parts list in case of 058-54800-EPG1-Z170.
Aug 2004	P-2004-14255	Failure of 058-54800-EPG2 back up overspeed module
Apr 2005	P-2005-08152	058-54800-EPG1 Old relay non-conformance in ICS
May 2005	P-2005-08388	058-54800-EPG2 Faulty overspeed trip monitor Z283 and high engine temperature relay KT282, no spares available
Jun 2005	P-2005-10459	058-54800-EPG2 unavailable
Jun 2005	P-2005-10470	058-54800-EPG2 Back up overspeed failure
Jul 2005	P-2005-12259	058-54800-EPG2 Unavailable, Back up overspeed relay failure
Aug 2005	P-2005-13651	Failed Calibration 058-54800-EPG2 over and under voltage trip relay time delay
Oct 2005	P-2005-16974	058-54800-EPG1 failed to start, failure of the relay K222-1
Jan 2006	P-2006-00981	058-54800-EPG2 failed during test run, spurious trip from vibration module
Jan 2006	P-2006-01145	058-54800-EPG2 still unavailable, extended outage for troubleshooting
Sept 2006	P-2006-16133	058-54800-EPG 1 Vibration detector. Defective switch
Sept 2006	P-2006-15920	Component non-conformance: 058-54800-EPG1-Z282
Sep 2006	P-2006-16494	Failed component in field: 058-54800-EPG1-Z353
Oct 2006	P-2006-18479	058-54800-EPG 2, speed switch failure
Jan 2007	P-2007-00712	Component non-conformance
Jan 2007	P-2007-01292	058-54800-EPG2-Z282 Defective
Jan 2007	P-2007-01649	058-54800 EPG Air Filter Unit condition
Jan 2007	P-2007-02186	Non-conformance EPG 2, Generator winding/bearing monitors.
Feb 2007	P-2007-02770	Non Conformance Vibration Monitor Board 058-54800-EPG2
Feb 2007	P-2007-03909	Critical spares for the EPG Machine
Mar 2007	P-2007-06738	058-54800-EPG1 Maintenance outage2007
Dec 2007	P-2007-07874	Emergency Power System Exceeds Predicted Future Unavailability
Apr 2007	P-2007-08037	Weather damage 058-54800-EPG1 air filter system control panel
Apr 2007	P-2007-09860	Loose Terminal Found 058-54800-EPG1
May 2007	P-2007-10525	EPG2 Unavailable causing L3 impairments of EPS, EWS, FAD and ECI recovery.
May 2007	P-2007-12186	EPG2 tripped on overspeed
May 2007	P-2007-12280	Lack of EPG Governor Replacement Parts

ONTARIOPOWER GENERATION

Pickering 'B' Chemistry Standards 13 - 79147

Superseding Business Case NK30-BCS-64510-00002-R000

1/ RECOMMENDATION:

We recommend a superseding release to reduce the scope for this wide ranging project (8 modifications). However, we are recommending no change in the currently approved release of $18.4M, as the scope reduction is offset by the issues summarized below.

The business objective of this old IIP project is to standardize and improve station Chemistry Control in order to enhance performance and increase the life of critical station equipment including pressure tubes, feeder tubes, boiler tubes, heavy water upgrader, moderator equipment and stator windings. Completion of this project is important to address several performance, safety, environmental, and reliability issues with modifications that will reduce work and lower costs. (See Alternative Section for details).

In August 2004, the Board of Directors approved a total project cost of $16.8M to complete seven (7) modifications designed to meet the Business Objectives of the project. Later in April 2005, funding was adjusted to $18.4M to accommodate an eight modification, a CEM Environmental Software Module. In December 2006, the D_20 Upgrader Feed Purification Modification was cancelled, triggering a $1.0M write off of sunk costs to OM&A. At this time, four modifications are complete, Life to Date expenditures are $15.0M (after write off), and $3.4M is required to complete the project (see background for details).

The Variance details are as follows:

1 Rework is required to fix problems encountered during the commissioning of two modifications — +$1.9M
- Plugged strainers on the Boiler Water & Steam Sampling modification ($1.0M)
- Flow control problems on the Hydrogen Addition system ($0.9M)

2 Several issues were encountered during installation — +$1.5M
- Discovery issues with degrading interfacing equipment
- Delays and mitigating activities resulting from late delivery of materials
- Additional shift coverage and overtime resulting from shortened outage schedules
- Increased Field Engineering due to changes in work processes such as Pressure Boundary

3 The D_20 Upgrader Feed Purification Modification was removed from the project scope because the installation could not be justified unless Pickering B's life is extended. Sunk costs totaling $1.0M were written off to OM&A (Dec 06). Approved funding needs to be reduced by $2.0M to reflect the new scope. — -$2.0M

4 The risk associated with completing this project has dropped considerably as all but one of the modifications is fully installed or designed. The contingency has been reduced to reflect the remaining risk. — -$1.4M

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2008	2009	2010	Later	Total
Currently Released	Superseding	16,726	1,684						18,410
Requested Now	Superseding	(1,907)	398	1,510					0
Future Funding Req'd	None								-
Total Project Costs		14,819	2,082	1,510	-	-	-	-	18,410
Other Costs									-
Grand Total		14,819	2,082	1,510	-	-	-	-	18,410
Investment Type Sustaining		Class Capital		(IEV) Impact on Ec Value (2,274)		IRR N/A		Discounted Payback N/A	

Submitted By:

T. Mitchell
Chief Nuclear Officer

24 APR 07
Date:

Reviewed by:

P. Charlebois
EVP & Chief Operating Officer

May 22/07
Date:

Finance Approval:

D. Power
V. P. Investment & ~~Business~~ Planning
CORPORATE

May 7/07
Date:

Line Approval (Per OAR Element 1.4 Variance):

J. Hankinson
President & C E.O.

Date:

BACKGROUND & ISSUES

Plant chemistry control is an essential element in the production of nuclear power. An effective Chemistry Program is required to achieve excellence in the Nuclear Power Industry. This project is a one time incremental effort designed to standardize and improve station chemistry control.

The Independent Integrated Performance Assessment (IIPA) identified that the general lack of chemistry standards at Ontario Power Generation Nuclear plants was a direct contributor to poor plant chemistry control, which in turn contributed to poor operational performance as well as equipment degradation. The IIPA found examples of specifications not being adequately addressed in the station chemistry control manuals, specification being chronically exceeded and chemistry excursions not reported. The chemical specifications had been written with the objective of minimizing the degradation of materials to prevent the premature end of the plant or its specific components. The general lack of the application of chemistry standards at OPG facilities was a direct contributor to poor plant chemistry control, which in turn contributed to poor operational performance.

The objective of this project is to implement the capital modifications necessary for compliance with the standardized chemistry program. Under this project we planned to implement the following seven modifications and develop CEM Environmental Software. The D_2O Upgrader Feed Purification modification was subsequently removed from the scope of the project since the business drivers do not justify proceeding with this modification at this time.

	Modification	Previous Release			This Request					Funding Required	Status
							Cost to Complete				
		Est Cost	Contingency	Total	LTD Costs (End Jan. 07)	Write Off (Dec 06)	Installation & Rework	Contingency	Total		
1	D20 Upgrader Feed Purification	2,034	931	2,965	1,000	(1,000)	-		-	(2,965)	cancelled
2	He Cover Gas Sampling	2,535	313	2,848	3,609		795	179	4,583	1,735	3 units complete
3	Boiler Water & Steam Sampling	4,485	358	4,843	5,102		989	147	6,238	1,395	rework
4	HTS Hydrogen Control	1,879	503	2,382	1,423		879	264	2,566	184	rework
5	Isolation Valve to HTS IX Column	1,503	163	1,666	868				868	(798)	complete
6	Feedtrain Shutdown Chemistry	583		583	604				604	21	complete
7	ICP Spectrometer	255		255	283				283	28	complete
8	CEM Environmental Software	1,638		1,638	1,638				1,638	-	complete
	Sub Total	**14,912**	**2,268**	**17,180**	**14,527**	**(1,000)**	**2,663**	**590**	**16,780**	**(400)**	
	Interest	1,230		1,230	1,441		189		1,630	400	
	Grand Total	**16,142**	**2,268**	**18,410**	**15,968**	**(1,000)**	**2,852**	**590**	**18,410**	**-**	

ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Stop the Project	Alt 1 (Recommended)		Alt 2	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost	Delay 1 year			
Revenue	0	0	0	0			
OM&A	(769)	(1,000)	0	0			
Capital	600	(18,410)	(3,447)	(4,114)			
NPV (after tax)	(349)	(15,525)	(2,623)	(2,941)			
Impact on Economic Value (IEV)	N/A	(15,176)	(2,274)	(2,592)			
IRR%	N/A	N/A	N/A	N/A			
Discounted Payback (Yrs)	N/A	N/A	N/A	N/A			

Stop the Project - Not Recommended

We do not recommend stopping this project because:

- The business objective of the project will not be met
- Several safety and environmental issues will not be addressed
- Cost saving opportunities will be lost
- The units will be configured differently
- The Boiler Steam and Water Sampling system cannot be fully placed in service as rework is required
- The HTS Hydrogen Control System is not fully meeting its design requirements
- Capital write offs to OM&A would be approximately $0.6M

Alternative 1 - Complete all Mods (except D20 Upgrader Feed Purification) - Recommended

We recommend completion of the following modifications at a remaining cost of $3.4M (including contingency) to complete the project:

- He Cover Gas Sampling System
- Boiler Steam & Water Sampling System
- HTS Hydrogen Control System

He Cover Gas Sampling System – Unit 5

Completion of Unit 5 will:

- improve reliability of moderator cover gas sampling and reduce the potential of an undetected explosive mixture
- add capability of on-line PHT cover gas sampling and reduce the potential of an undetected explosive mixture
- reduce risk of outage extension due to GC unavailability during unit start-up
- reduce control maintenance resources required to maintain the gas chromatograph
- complete the modification on the fourth and final Pick-B unit and provide constant configuration among the units

Boiler Steam & Water Sampling System (All Units)

Completion of the rework required to resolve the plugging of newly installed strainers will enable heat exchangers to be placed in service and provide constant sample temperature. This will:

- improve accuracy of results which allows optimization of chemical addition rates in order to prolong the life of the feedwater equipment and boiler tubes; and also to prevent unnecessary discharges of excessive chemicals to the environment
- improve accuracy of Chemistry WANO Index
- eliminate Chem Tech resources to recalibrate for temperature changes (up to 6 hr per shift during fluctuating temperatures)
- eliminate action levels based on inaccurate results (example: erroneous high oxygen level could lead to isolation of condenser water boxes and associated unit derating)

HTS Hydrogen Control System (All Units)

Completion of the rework on all units to correct flow control at low rates will:

- minimize excursions of high dissolved H_2 in the PHT system resulting in a potentially explosive mixture and increased rates of hydrogen absorption and hydrogen embrittlement.
- minimize excursions of low dissolved H_2 in the PHT system resulting in increased corrosion rates and potential shutdown limits.
- minimize Chemical Technician resources to take additional samples (1 hour/shift)
- minimize dose as the current sample point is in the RB
- enable injection via dual headers per design
- minimize potential to delay Unit start-up if the system is out of specification
- minimize Operator resources to purge excess hydrogen from the PHT
- optimize consumption of Hydrogen and Helium gases
- eliminate cost of maintaining metering valves ($60k every five years)

Alternative 2 - Delay Project - Not Recommended

We do not recommend delaying the project because it will increase the cost and delay the benefits. The project team is in place, the preferred contractor has been engaged and the work is scheduled in upcoming outages. This project has already been postponed several times and the work to complete ($3.4M) is for the most part, rework required to commission modifications.

Alternative 3 – Complete Original Project Scope - Not Recommended

We do not recommend completing the original project scope. The installation of the D_20 Upgrader Feed Purification system cannot be justified unless the life of Pickering 'B' is extended. It has been removed from the project scope with confirmation from the Project Sponsor). This modification can be re-evaluated as part of a life extension initiative. Sunk costs of $1.0M were written off to OM&A in 2006.

D_20 Upgrader Feed Purification (written off in 2006)

The business driver for this modification was to reduce the rate of deterioration of the upgrader packing by installing the UV oxidation unit currently owned by OPG (purchased outside this project). Reducing the rate of deterioration may have:

- reduced the number of drums stored on site which reduces the risk of drum leaks, environmental spills, and dose to workers
- prevented the cost associated with external assistance in processing drums of water contaminated with organics
- reduced the loss of upgrader capacity as a result of plugging (1 month outage per 7 years for each of 2

upgraders)

- prevented the cost associated with cleaning the upgrader packing in each of the two upgraders
- reduced the cost associated with charcoal consumption and disposal currently required to removed organics from upgrader feed
- allowed the upgrader feed specification (Total Organic Carbon less than 1 ppm) to be met which is one of the outstanding requirements to improve the upgrader System Health Window from Yellow to White

A decision to write off the sunk costs of $1.0M was made in 2006 because at the current rate of deterioration, the upgrading capacity will remain above station needs until well past the current life of Pickering B. Alternate solutions are being investigated to reduce drum inventory. The cost of upgrader distributor cleaning and charcoal consumption are estimated at less than the cost of the modification

Alternative 4 – **- Not Recommended**

Alternative 5 – **- Not Recommended**

'/ THE PROPOSAL

We recommend completion of the following modifications with the following targets:

- He Cover Gas Sampling System December 2007
- Boiler Steam & Water Sampling System December 2008
- HTS Hydrogen Control System December 2008

5/ QUALITATIVE FACTORS

None other than what is stated in the Alternative section.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
There is risk of discovery issues on the Duplex Strainer modification. Installation and commissioning procedures have not yet been prepared. Modification has not yet been installed on any unit.	cost over run	Medium	A specific contingency of [redacted] has been applied to Duplex Strainer modification.	Low
There is risk of discovery issues on the Mass Flow Controller modification. The design is not complete.	cost over run	Medium	Design estimates (TIS Sheets) have been obtained from Projects Design. Design costs and progress reviews will be performed on a weekly basis to monitor actual costs versus estimate. A specific contingency of [redacted] has been added to the MFC DCP to address unforseen design changes prior to the DCP revision.	Low
Installation costs for the U5 Gas Chromatograph may be higher than budgeted due to delays or unforseen interferences.	cost over run	Medium	Scope of Work documents prepared and submitted to contractor to ensure full understanding of scope. TIS Sheets and Contractor Estimates have been received for all remaining work. A specific contingency of [redacted] has been added to address delays and unforeseen interferences. Another specific contingency of [redacted] has been added to this DCP in case there is a compressed outage window during P751.	Low
Scope				
The scope of work for DCPs 406 & 601, is fairly well understood, however the designs are not finalized and	cost over run	Low	Preliminary COMS has been completed on the revision to DCP 601. Final COMS has been completed on the revisions to DCP 406.	Low

the scope may increase or decrease depending on stakeholder input.				
Addition of MFC on Hydrogen Addition System is new unproven technology.	cost over run	**Low**	Different Alternatives were presented during the Preliminary COMS meeting. The Mass Flow Controllers was accepted as the preferred alternative. Recent OPEX has shown that a similar device was installed on Pickering 'A' without success. A review is being conducted by Design to confirm the Mass Flow Controller is a viable option.	**Low**
Schedule				
There is a Potential for Delays During Outage Installation Work.	Any delays in the installation can impact critical path during the Outage and incur extra Contractor costs. These delays were noted in the cost section and a contingency applied.	**Medium**	The installation of the Gas Chromatograph for P751 will be on the fourth and final Unit. All lessons learned from previous installations have been incorporated into Work Plans. A contract has been let out to the same vendor that performed the last two intallations to ensure the schedule is met.	**Low**
Changes to the IOP Schedule for not meeting T minus targets.	The schedule for the installation of the MFCs and the Duplex Strainers will all be done using the IOP process. Delays on the IOP schedule will mean that the modifications will have to remain open longer and potentially incur more costs.	**Medium**	Project Engineers will attend T minus meetings to ensure project stays on the IOP schedule. A contingency of 2 months has been built into the schedule to allow for IOP delays.	**Low**
Delay to DCP Revision.	Installation will be impacted if Design does not meet their agreed upon dates for the revisions of DCPs 406 and 601. T-26 milestones need to be met to ensure a timely installation and maintain the proposed budget.	**Low**	Design has provided TIS sheets for the two jobs. They have also provided a TCD date for DCP revisions that will be added to the target P3 file. A float of 2 weeks has been allocated to ensure no overrun in the Design Schedule.	**Low**
Resources				
Project Engineers are removed from their modifications (DCPs 601 & 406) for use on other projects.	Removal of project engineer (MTL) from DCP 406 or 601 will delay the schedule of the DCP and the project.	**Medium**	Adequate project resources have been assigned for anticipated work load.	**Low**
Projects cannot obtain adequate station resources For IOP Work.	The Modification would not be completed as per schedule.	**Low**	Installation and commissioning tasks will be properly assessed and scheduled. All tasks will be "C" tasks, which means they have to	**Low**

Vendor not available during commissioning of GC.	Delay would impact on Commissioning of Gas Chromatograph. If the vendor is not available during commissionig of the Gas Chromatograph, it will impact the return to service of the system, which could potentially affect the Outage End Date.	Medium	be completed in the week they are scheduled. A rigorous COMS review has been conducted on all remaining modifications. Two of the remaining three modifications are rework to the original modification. The GC is the final unit install and no rework is anticipated. Stakeholders have been involved in COMS reviews and challenge meetings.	Low
Technical				
Modifications Do Not Meet the Design Intent and/or Design Requirements	Modification would require significant redesign or rework.	Medium	A rigorous COMS review has been conducted on all remaining modifications. Two of the remaining three modifications are rework to the original modification. The GC is the final unit install and no rework is anticipated. Stakeholders have been involved in COMS reviews and challenge meetings.	Low
Regulatory				
No Significant Risk				
Environmental				
No Significant Risk				
Health & Safety				
Workplace Injury of Serious MRPH Event	Unplanned intake/exposure to tritium and/or gamma. Potential for personal injury.	Low	The use of experienced trades personnel, the completion of the COMS process, as well the use of Event Free Tools (including procedural compliance) will help minimize and eliminate any such events. Work Plans have all been reviewed by Conventional Safety and Radiological Safety. Pre-job briefings are given every shift. JSAs will be prepared for all modifications.	Low

Personnel Contamination	Possible high MRPH, fire, explosion, or peronal injury.	**Medium**	One leg of the Hydrogen Addition System will be isolated at a time to perform the modification. This will ensure that hydrogen levels are not increased in the system which wil prevent an explosive mixture in the D2O Storage Tank. Blue Coveralls will be worn during the installation of the modification. All work plans will be reviewed by Conventional Safety.	**Low**
Investment				
Modifications Do Not Meet Design Requirements	Higher Costs to Rectify Problems	**Low**	Modification details have been extensively reviewed and critiqued by all stakeholders. An in depth OPEX review and analysis has been done on all modifications and lessons learned incorporated. No new technologies are being installed. All modifications involve equipment previously used in the Nuclear Industry.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Dec 2008	Jun 2009	Manager, Chemistry

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Performance Criteria and Reliability	Design Requirements	Modifications meet the performance and reliability criteria specified in the Design Requirements	Design acceptance of the Commissioning Report	Project Manager
2.	Stakeholder Acceptance of AFS	Installation and Commissioning of the modifications is as per DCN Packages	AFS Report	Signed Final AFS Declarations an acceptance of any Open Items	Project Manager
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

Abbreviations and Acronyms

AFS - Available For Service
BCS - Business Case Summary
BTU - Building Trade Unions
CMO - Contract Management Office
CNSC - Canadian Nuclear Safety Commission
COMS - Constructability, Operability, Maintainability, and Safety
CSA - Cost and Schedule Analyst
CWP - Comprehensive Work Plan
DA - Design Authority
DCN - Design Change Notice
DCP - Design Change Package
DOM - Director, Operations and Maintenance
DTL - Design Team Leader
ECC - Engineering Change Control
ECN - Engineering Change Notice
ECR - Engineering Change Request
EPSCA – Electrical Power Systems Construction Association
FIPR - Fabrication and Installation Package Release
FLM - First Line Manager
FTL - Field Team Leader
GC - Gas Chromatograph
He - Helium
HOR - Holder of Record
ICP - Inductively Coupled Plasma
IIP - Integrated Improvement Program
IIPA - Independent Integrated Performance Assessment
IX - Ion Exchange
ITP - Inspection and Test Plan
MA - Maintenance Authority
MFC - Mass Flow Controller
MR - Material Request
MPSR - Major Project Summary Report
NPMR - Nuclear Project Management Reporting
OAR - Organizational Authority Register
OM&A - Operating, Maintenance and Administration
OPEX - Operating Experience
OPG - Ontario Power Generation
P3 - Primavera Scheduling Tool
PCRAF - Project Change Request Authorization Form
PDRI - Project Definition Rating Index
PEP - Project Execution Plan
PHTS - Primary Heat Transport System
PLEP - Pickering 'B' Plant Life Extension Project
PIR - Post-Implementation Review
PMO - Project Management Office
PO - Purchase Order
PSM - Plan Start Milestone
QA - Quality Assurance
SCR - Station Condition Record
SPOC - Single Point Of Contact
SWC - System Window Coordinator
TCU - Temperature Control Unit
UV - Ultraviolet
WBS - Work Breakdown Structure

Appendix "B" Project Funding History

$ 000's			All Existing and Planned Releases (incl contingency) Cumulative Values								
Release Type	Month	Year	2002	2003	2004	2005	2006	2007	2008	Later	Total
Full	Feb	2001	3,996	1,222							5,218
Superseding	Aug	2004	4,188	1,770	3,133	4,729	2,672	281			16,772
Adjustment	Apr	2005	4,188	1,770	1,568	4,500	4 700	1,684			18,410
Superseding	May	2007	4,188	1,770	1,568	3,591	3,702	2,082	1,509		18,410
											0
											0
											0
LTD Spent	Jan	2007	4,188	1,770	1,568	3,591	3.702	149			14,968

Comments:

In April 2005, funding was adjusted to $18.4M to accommodate Head Office IIP costs relating to the development of a CEM Environmental Software Module that had been charged to the project.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

Estimate includes specific contingencies for:

- Duplex Strainer Modification [redacted]
- Mass Flow Controller
- Gas Chromatograph

  Total

Cost of Stopping the Project estimated to be $400K (project management and design)

Cost of delaying the project for one year is estimated to cost $500K for demobilization / remobilization and 5% for cost increases.

LTD Jan 2007 Spending = $14,968 (including $1.0M 2006 write off)

LTD Jan 2007 In Service Declarations = 14,340K

Write off for "Stop the Project" = $14,968K less $14,340K = $628K (2007)

Financial Assumptions:

WACC = 7%

Project / Station End of Life Assumptions:

Units 5, 6, 7 Spring 2014
Unit 8 Spring 2016

Energy Price / Production Assumptions:

N/A

Operating Cost Assumptions:

Labour costs for Hydrogen Addition estimated at [redacted]er year
Cost to repair metering valves estimated a[redacted] every 5 years

Other Assumptions:

Pickering 'B' Chemistry Standards 13 - 79147

Superseding Business Case NK30-BCS-64510-00002-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2006	This Release 2007	This Release 2008					Later	Total
Project Management (OPG)	938	249	132						1,319
Engineering & Drafting (OPG)	3,808	145	162						4,115
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Installation Support (FE)									
D_2O Upgrader write off									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	**14,819**	**2,082**	**1,510**	-	-	-	-	-	**18,410**
2007-2011 Business Plan	17,117	4,030	120						21,267
Variance to Business Plan	**(2,298)**	**(2,243)**	**1,095**	-	-	-	-	-	**(3,447)**
Committed Cost									
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	**14,819**	**1,787**	**1,215**	-	-	-	-	-	**17,820**
Total Release (incl contingency)	**14,819**	**2,082**	**1,510**	-	-	-	-	-	**18,410**
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	Up to - 40%		Quality of Estimate	Release + 15% to - 10%	
3[rd] Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	No	Budgetary Quote(s)	Yes	Phase 1 Actual Used	Yes
Similar Projects	No	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by May 2007.

Reviewed By:

Vince Tzambazis — March 28 2007

Vince Tzambazis
Project Manager — Date:

Approved By:

Randy Ludlow — 2007 · 3 · 29

Randy Ludlow
Eng & Mods Manager (Strat IV) — Date:

Pickering 'B' Chemistry Standards 13 - 79147

Superseding Business Case NK30-BCS-64510-00002-R000

Attachment "B" **Project Variance Analysis**

Capital	LTD Dec 2006	Total Project: Last BCS May 2004	Total Project: This BCS Feb 2007	Variance	Comments
Project Management (OPG)	938	1,066	1,318	252	Additional project management required due to rework.
Engineering & Drafting (OPG)	3,808	3,564	4,115	551	Cost overrun to resolve deficiencies identified during commissioning.
Material	[redacted]				
Installation – PWU, BTU	[redacted]				
Contract - Design	[redacted]				
Contract - Installation	[redacted]				
Contract - Other	[redacted]				
Installation Support (FE)	[redacted]				
D_2O Upgrader Write Off	[redacted]				
Interest (Capital Project Only)	[redacted]				
Project Costs (excl contingency)	[redacted]				
General Contingency	[redacted]				
Specific Contingency	[redacted]				
Project Costs (incl contingency)	**14,819**	**17,410**	**18,410**	**1,000**	
Committed Cost				-	
Inventory Write Off Required				-	
Spare Parts / Inventory				-	
Total Release (incl contingency)	**14,819**	**17,410**	**18,410**	**1,000**	
Total Release (excl contingency)	**14,819**	**15,142**	**17,820**	**2,678**	
Ongoing OM&A (non-project)				-	
Removal Costs (incl in above)				-	

Comments:

1. An underestimation in the cost of BTU trades. Numerous discovery issues such as degraded interfacing equipment have been encountered. There have also been numerous delays such as late delivery of materials. Mitigating actions to perform more shop fabrication and testing has helped but these activities were not budgeted. Also support activities such as Holder of Record Duties, Maintenance Authority duties, material tracking, training, EPSCA travel, supervision, coordination, and reporting were all unfunded.

2. Shortened outage schedules have required additional shift coverage which resulted in more work turnovers and additional premium pay.

3. An underestimation in the cost of Field Engineering support. Discovery issues have required additional oversight as well as revisions to ITPs, FIPRs, and Comprehensive Work Packages (CWP). Also, changes to work processes including the Pressure Boundary process have increased the Field Engineering workload.

4. Design deficiencies, including the plugged strainers on the Boiler Steam and Sampling Panels and flow control problems on the Hydrogen Addition system that were discovered during commissioning will require design rework as well as additional work to install and commission the revised design.

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
03	Jul	2007	He Sampling Gas U5 AFS
01	Feb	2008	Hyrogen Addition U8 (MFC) AFS
25	Feb	2008	BS&W U8 Final AFS
01	Apr	2008	Hydrogen Addition U5 (MFC) AFS
09	Apr	2008	BS&W U5 Final AFS
01	May	2008	Hydrogen Addition U6 (MFC) AFS
05	May	2008	BS&W U6 Final AFS
02	Jun	2008	Hydrogen Addition U7 (MFC) AFS
16	Jun	2008	BS&W U7 Final AFS
15	Dec	2008	Chemistry Standards Project Complete

A Project Execution Plan (PEP) will be approved by May 2007

Comments:

Please refer to Tab 1

The Business Case Summary for the Second Darlington Full Scope Simulator, Project No.: 28452, is combined with the Business Case Summary for DLC Modifications – Simulator Based Training, Project No.: 28453.

DNGS D2O Storage and Drum Handling Project 16 - 31555

Developmental Release Business Case Summary D-BCS-38000-10001-R001

1/ RECOMMENDATION:

We recommend approval of a Developmental Release of $3,600k (including $840k contingency) to complete preliminary design, initiate detailed design, initiate Requests for Quotations for long-lead materials and develop a Partial Release for the DNGS D_2O Storage and Drum Handling Project by November, 2007. A Partial Release will be requested upon completion of preliminary engineering to facilitate a seamless transition to detailed design, long-lead material procurement, initiate Requests for Proposal for the construction contract and develop the Full Release. This funding strategy will minimize cost and schedule delays.

The business objectives of this project are as follows:

- Improve detritiation capability within OPG.
- Improve operational flexibility and ability to segregate different streams of D_2O to support various operation and outage scenarios in DND (ie: unit outages, SCO/VBO or upgrader outages)
- Improve the management of drum inventories in DND.
- Allow Isotope Sales Department to pursue new business opportunities.

Kinectrics was commissioned to study the Heavy Water storage and drum handling issues from an overall OPG perspective. The recommended modification for DNGS is to extend the existing HWMB to house additional 8 x 50Mg multi-purpose storage tanks and to provide additional drum handling/storage space, and install a drum testing facility. The recommendation is based on the understanding that DNGS's drums will be cleaned off site at PNGS's new drum cleaning facility, and the additional DNGS tanks will provide storage flexibility that benefits PNGS's detritiation program.

Choose One	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	N/A								-
Requested Now	Developmental		1,872	1,728					3,600
Future Funding Req'd				3,992	13,253	14,938	600		32,783
Total Project Costs		-	1,872	5,720	13,253	14,938	600	-	36,383
Other Costs									-
Ongoing Costs									-
Grand Total		-	1,872	5,720	13,253	14,938	600	-	36,383
Investment Type		Class		(IEV) Impact on Ec Value		IRR		Discounted Payback	
Value Enhancing		Capital		13,554		14.8%		9.8	

Submitted By:

Rumina Velshi
Director, Commercial Activities

Date:

Finance Approval:

Randy Leavitt
Director, Investment Management

Nov 22, 2006
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Larry Nichol
Director, TRF

Nov 24, 2006
Date:

2/ BACKGROUND & ISSUES

OPG needs to improve its overall ability in managing its D_2O inventories to support continuous station operations in a safe and cost efficient manner. In December 2004, Kinectrics Inc. completed a study "Strategic Option Study for OPG Heavy Water Storage and Drum Handling", (Ref; K-011043-001-RA-0001-R00A). In April 2006, Kinectrics Inc. was contracted by this Project to further investigate the issues at Darlington and Pickering and to develop options which would address OPG's D_2O management needs.

The main objectives of this project are as follows:

1. Improve the detritiation process within OPG.
2. Improve operational flexibility and ability to segregate different streams of D_2O to support normal operation and outages.
3. Improve the management of drums in the station and to reduce to associated drum handling-related, radiological and conventional safety hazards.
4. Allow Isotope Sales Department to pursue new business opportunities.

Plant Life Extension and P2/P3 decommissioning are not part of the scope of this project. However, the impact of plant life extension on this project was considered in the choice of location (Reference Section 3).

With respect to DNGS, the Kinectrics study identified problems in three areas of the D_2O Management System with regard to the project objectives. They are reactor grade D_2O storage, downgraded D_2O storage, and drum storage and handling.

rea 1: Reactor Grade D_2O Storage

Storage & Inventory (S&I) Tanks are used for the storage of reactor grade D_2O such as TRF Feed, TRF Product, Moderator D_2O, PHT D_2O, and Station Upgrader Product (SUP).

PROBLEMS	ISSUES	CONSEQUENCES/IMPACTS
1) Lack of storage at DIOTS limits TRF flexibility to build up a large volume of Hi-Ci feed stock and/or Low Ci TRF product.	• TRF's Hi-Curie (Ci) feed stock relies heavily on the ability from other stations to ship, and that their shipment may not align with the TRF availability or ability to receive. • Inadequate volume of tankage for low Ci TRF product to fully support OPG's detritiation program or to support Isotope sales.	• Inefficient use of TRF & OPG resources as less overall tritium is removed from the entire fleet of nuclear units for the same TRF operating costs. • The inability to fully support PNGS's detritiation program endangers PNGS's OP&P limit. • Inability to meet contractual obligation (estimated in loss of revenue through Isotope Sales, at [redacted] since 2001 from [redacted] and restricts Isotope Sales from pursuing new business with domestic customers of up to [redacted]
2) Insufficient storage space to support moderator drain in a planned outage.	• All existing moderator grade D_2O must be emptied out (~ 100Mg) & relocated from S&I tanks to DIOTS or offsite to accommodate a moderator drain.	• If DIOTS is used, then this interrupts TRF shipping & receiving (see item #1) • May require offsite storage which can cost $1.5M for each occurrence. • Risk of delaying outage if offsite storage is unavailable.

PROBLEMS	ISSUES	CONSEQUENCES/IMPACTS
4) Insufficient storage space to support SCO or VBO.	• More PHT grade D_2O must be accumulated prior to an SCO or VBO to accommodate 4 units shrinkage & loss make-ups	• Failure to accumulate PHT D_2O could potentially cost OPG [redacted]o lease D_2O (140Mg) from an external source. • Risk of delaying outage if external source is unavailable.
5) Insufficient storage space to support PHT Low Level Drain (LLDS) in SCO/VBO	• With the extra PHT grade D_2O accumulated prior to SCO/VBO there is insufficient storage space to accommodate the swell associated with re-starting 3 units while the 4th unit remains in the LLD state	• If PHT grade D_2O is stored in the moderator S&I tanks to accommodate the swell & LLD it increases the risk of downgrading moderator grade D_2O, with a potential cost to OPG of $1.5M to re-upgrade. • If DIOTS is used to store PHT D_2O see item #1.

Area 2: Downgraded D_2O Storage

Downgraded D_2O storage tanks are used at the IXCU for the collection and process of downgraded recovery water

PROBLEMS	ISSUES	CONSEQUENCES/IMPACTS
6) Insufficient downgraded D_2O storage space to support acute recovery events or SUP outage.	• Alternate temporary storage methods such as using reactor grade D_2O tanks at DIOTS or drums to bridge the gap.	• Increased risk of downgrading reactor grade D_2O. This situation downgraded 60Mg of moderator D_2O in 2003, which cost DNGS approximately $0.9M to upgrade. • The use of drums increases housekeeping issues, and add drum purchasing cost of approx. $30K / yr. • Also see item #1
7) Insufficient downgraded storage to provide operational flexibility when processing high TOC D_2O.	• When high TOC levels are present in the downgraded D_2O after being processed through the IXCU system the TOC must be removed prior to processing through the SUP. After the TOC is removed, via the UV system, this D_2O must then be reprocessed through the IXCU to remove increased conductivity created by the UV system.	• The SUP is forced to go onto reflux due to lack of feed while the D_2O is being cleaned up. (SUP capacity factor reduced). • The recycling of 'UV processed' D_2O through the IXCU further reduces the downgraded storage availability. • It may also lead to storing downgraded water in DIOTS or in drums (see item 1).
8) Insufficient downgraded storage space and flexibility to support the efficient segregation and processing of high and low Ci recovery streams of D_2O during an extended TRF outage.	• During an extended TRF outage, the only source internal to DNGS to obtain more low Ci make-up PHT D_2O required to keep DNGS units within OP&P limits is by processing the high and low Ci recovery streams separately through the "single" clean-up and upgrading system. When switching from high Ci to low Ci stream, low Ci D_2O is required to flush the system (creating a mid Ci product) for a sufficient time before the low Ci product is produced at the SUP.	• The lack of downgraded storage space requires more switching between the 2 streams & thus requires more flushing which reduces the availability of low Ci products. If the amount of PHT makeup D_2O falls below 210Mg then DNGS would be required to: a) Lease low Ci D_2O from [redacted]which had cost OPG [redacted]ay. b) Mix in available higher Ci D_2O with the available lower Ci D_2O (this would increase the tritium levels in the PHT system) to maintain the level. This increases the risk

		of approaching OP&P limits and increases fuel burn-up cost. c) Use virgin D_2O as makeup to the PHT system. This will cost OPG $300 /Kg. • The frequent switching of streams further stress the inadequacies of downgraded storage (see item 6 & 7).

Area 3: Drum Storage and Handling

This area is required to receive, ship and handle (ie: pressure testing and cleaning) drums used by the DNGS units to temporarily store recovered D_2O, store downgraded D_2O with high TOC for processing, or from external sources in support of Isotope Sales.

PROBLEMS	ISSUES	CONSEQUENCES/IMPACTS
9) Insufficient floor space available in the HWMB to store & handle D_2O drums.	• Drums are spread around in the HWMB and inside the station. Some of the locations that are storing these D_2O drums may not be designated normally for this purpose. • Increase rework as drums need to be moved around or relocated more than once. • Minimal space available for drums from external sources.	• D_2O drums that are stored in re-designated areas can impede normal flow of operation & increase chance for human performance errors. • Increased difficulties to maintain proper housekeeping within HWMB or the station. • Increased workers' health and safety concerns with additional drum handling. • An inefficient use of Operators. • Restricts Isotope Sales from pursuing new business, (i.e. importing drums of D_2O from foreign customers). This contributes to a potential increase revenue up to $4M/yr
10) Lack of on-site drum pressure testing facility, and or cleaning facility.	• Drums are sent off site to be pressure tested before they can be reused for D_2O shipment. • Lack of available clean drums requires operators to re-using dirty drums that will contaminate relatively 'clean' D_2O.	• Cost of external testing of drums is [redacted] or [redacted] • Drums that cannot be cleaned before reuse amplify the storage & housekeeping problem, and increase reworks when "clean" D_2O is contaminated. .

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Choose One	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3	Alt 4	Alt 5
Revenue	-	87,790	87,790	69,610			
Project Cost	-	(34,588)	(34,588)	36,639			
NPV (after tax)	(9,206)	4,448	4,448	(3,905)			
Impact on Economic Value (IEV)		13,654	13,654	5,301			
IRR%	N/A	14.8%	14.8%	N/A			
Discounted Payback (Yrs)	N/A	9.8	9.8	N/A			

Status Quo - Not Recommended

Maintaining the status quo is not recommended. Continuing to operate as is will result in DNGS experiencing the current issues identified in section 2 with associated costs and risks.

The lack of TRF Feed and Product storage limits HWMB's ability to receive and store D_2O. This restricts its ability to process more high Ci feed, which contributes to the inefficient operation of the TRF, and limits TRF from processing more D_2O from external customers ([redacted] in potential sales). It also contributes to the difficulties for OPG to adhere to its detritiation program which causes continued increase in the tritium levels in OPG, particularly at Pickering. Increasing tritium levels result in increased tritium emission with environmental impacts, increased fuel burn-up costs, increased dose expenditure and regulatory impact due to potentially exceeding the OP&P limits.

The lack of D_2O storage limits DNGS's ability to plan and execute its maintenance outages for the station, SUP and TRF with the following potential costs and risks; $1.5M to ship moderator D_2O off site, $1.5M to upgrade D_2O, and/or [redacted] to lease low Ci D_2O for PHT make-up.

The lack of recovery storage limits DNGS's ability to support acute events and high TOC recoveries. This causes backlog at the cleanup systems and increases the use of drums. As the station ages and more maintenance is performed on reactor systems, more acute events and recoveries with high TOC are anticipated. It also limits DNGS' ability to recover adequate low Ci products to support units' operation during an extensive TRF outage.

The lack of space to store drums results in poor housekeeping in the station & HWMB, and inefficient use of operator resources, which costs DNG approximately $64K/year. Workers will continue be exposed to increased health and safety concerns related to drum handling. Also, the lack of drum storage restricts Isotope Sales from pursuing new external customers, contributing to the potential [redacted] in increased sales.

Without a drum testing facility, DNGS will have to incur an expense of approximately [redacted] to continue to ship drums offsite for testing, which limits its flexibility to manage its shipments in a timely manner.

Alternative 1 - Build a 26m x 12m addition with 8x50Mg storage tanks and with drum storage and testing facilities - Recommended

Construct a 26m x 12m HWMB extension to house 8x50 Mg multi-purpose storage tanks, a 12m x 14m drum storage area, and drum testing facility.

Tank ID	Tank Spec	Proposed usage
1A/1B	2 x 50 Mg – class III	High Ci – Moderator/TRF Feed/SUP Product
2A/2B	2 x 50 Mg – class III	Low Ci – PHT / TRF Product
3A/3B	2 x 50 Mg – class III	Downgraded Dirty
4A/4B	2 x 50 Mg – class III	Downgraded Clean

The additional multi-purpose tanks can be used to store either reactor grade D_2O or downgraded D_2O. This addition will address all the problem areas, minimizing the risks and costs identified above.

It will also achieve the main objectives of this project

1. Improve the detritiation process within OPG:

   The additional reactor grade D_2O storage at DNGS allows more schedule flexibility to ship or receive D_2O to/from the TRF to support OPG detritiation program. This additional flexibility can help to relieve some storage pressure at PNGS as their high Ci D_2O can be shipped for detritiation more readily. The additional space also allows TRF to accumulate a larger volume of high Ci D_2O to support continuous TRF detritiation operation and to accumulate a larger reservoir of TRF product to support OPG operations or detritiation efforts. This will improve TRF efficiency and the annual TRF's through-put as more tritium is removed for the same unit operating cost and will relieve some reliability pressure on TRF.

2. Improve operational flexibility to segregate different streams of D2O:

   The additional reactor grade D_2O storage will allow storage of either high or low Ci products. This improves flexibility for D2O movement & planning and enhances shipping & receiving capability. It also provides additional reactor grade D_2O storage capacity to support moderator drains, SCO/VBO and extended TRF outages without having to ship D_2O off site or deal with the risk of downgrading reactor grade D_2O.

   The additional downgraded D_2O storage will provide adequate storage capacity to support normal operations and outages even during acute recovery events or high TOC scenario. This will ensure 'clean' feed is always available to the SUP and reduces the amount of time it is forced to go into reflux mode and improve SUP capacity factor. It will also reduce recovery backlogs, operator work-arounds and amount of drumming required during acute events, which further improves housekeeping and associated worker health and safety issues. The additional downgraded storage also improves the flexibility to process the high or low Ci recovery streams separately with less switching of streams when processing through the SUP. This improvement allows more low Ci D_2O to be available during an extended TRF outage, thereby reducing the risk & cost of leasing low Ci D2O from other sources.

3. Improve the management of drums :

   A new 'designated' Drum Storage & Handling Facility (DS&HF) in HWMB that can store up to 350 drums will allow all D_2O drums to be stored in a central location. This capability will improve the management of drums & D_2O inventory. The facility will improve housekeeping, reduce rework and reduce drum handling-related radiological and conventional safety hazards

   A new Drum Testing Facility (DTF) will eliminate the costs associated with having drums tested by a 3rd party including shipping and handling cost. It will allow HWMB to manage its drum QA requirements in house and provide the flexibility for operations to certify drums on a as needed basis to meet sales commitments.

   A new Drum Cleaning Facility (DCF) will be proposed to be installed in PNGS. The new DCF will help in the overall management of drums within OPG.

4. Allow Isotope Sales Department to pursue new business opportunities

   The operational improvements in the HWMB and the improved efficiency of the TRF will provide the flexibility and capacity for Isotope Sales Department to meet current contractual obligations and to pursue new business. The forecast for the increased business is estimated to be [redacted] in gross revenue.

Note: The recommended modification is less than what was originally proposed in the Charter. This recommendation was reviewed and subsequently agreed to by the stakeholders in the Project Challenge Meeting on August 18, 2006 that it can satisfy their needs and resolve the issues at DNGS.

Alternative 2 - Delay Project - Not Recommended

Delaying the project is not recommended. This would require DNGS to continue its dealing with current operational issues and the risks & costs similar to the "Status-Quo" option longer and reduce the number of years available to recover project costs through increased sales.

If OPG makes the final decision on Plant Life Extension (PLE) in the future, the proposed site location for this project will still have sufficient space to build a second addition to install more D_2O tanks. An alternative option is to include a basement area in the current proposed site to accommodate more D_2O tanks in the future when needed. However, this decision must be made now in order to be incorporated into the current design, and this will increase the current cost estimate and further impose project risks from any unknown discoveries when the geotechnical analysis of the soil is performed.

Alternative 3 – - Not Recommended

Alternative 4 – - Not Recommended

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

The following are the objectives and deliverables of this Developmental Release BCS:

- Prepare and award a Design contract for Preliminary Engineering & Detailed Design
- Complete Preliminary Engineering, (up to 40% Detailed Engineering).
- Issue Tech Spec for Long Lead Material
- Review/approve Preliminary Engineering
- Initiate Detailed Design
- Prepare Preliminary PEP
- Issue a Partial Release BCS

Refer to Appendix C for a list of the project milestones.

5/ QUALITATIVE FACTORS

The successful completion of this project will improve the following:
Government Relations

- Reduce tritium emissions throughout OPG
- Reduce risk of infringing on regulatory limits

Customer Relations

- Increasing OPG's capability and flexibility to process D_2O will improve customer relations by meeting contractual obligations with Bruce Power for detritiation services and provide the ability to increase detritiation services.

Technical/Operational Considerations

- Improve efficiency of TRF operation and increase the overall amount of tritium removed from the OPG D_2O inventory.
- Improve availability of low Ci reactor grade D_2O for operational & outage needs
- Improve HWMB capability & flexibility to support any outage or acute events thus reducing the risks and cost to extend an outage.
- Improve management of detritiation programs particularly at Pickering by reducing the dependency on TRF availability

Health & Safety

- Reduced tritium levels will reduce worker dose.
- Additional drum storage will improve housekeeping and reduce drum handling requirements, thereby reducing the related health and safety concerns.
- Reduce operator work arounds and extra operator actions that are required to maneuver various grades of D2O into unconventional storage arrangements.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Overall project cost exceeds current estimate	Unable to accomplish all project objectives without further release of funds	**High**	Detailed conceptual study completed by Kinectrics. Helyar review of project cost. Adopt optimal contracting strategy to mitigate cost escalation. Further fine tuning of overall project schedule and cost via partial BCS.	**Medium**
Changes to the funding release strategy and/or fine tuning of contracting stategy may impact overall cost and schedule	Could cause a delay to the schedule & increase costs	**High**	Review contracting stategy and design and installation requirements with Supply Chain, Procurement, Design & Legal	**Medium**
Scope				
Preliminary/Detailed Design may result in an increase in scope.	Changes in scope will delay the schedule and add cost to the project.	**Medium**	Further scope identified during preliminary design will be challenged by projects & have to be agreed by all stakeholders & sponsor.	**Low**
Schedule				
Delay in the issuing of Design contract due to rigorous management, supply chain and legal reviews of the RFP.	Schedule delay	**High**	Early involvment of Supply Chain, Legal, Taxation etc to ensure that all the required information is included in the RFP	**Medium**
Fine tuning of contracting stategy may impact overall cost and schedule	Require changes to funding release strategy which could cause a delay to the schedule & costs	**High**	Review contracting stategy and design and installation requirements with Supply Chain, Procurement, Design & Legal	**Medium**
Insufficient information to determine accurately the	Delay to schedule	**Medium**	Fine tuning of final design deliverables timeline is available via partial BCS	**Low**

timeline of design deliverables				
Design deliverables not on time	Delay to schedule		Select approved vendor, provide clear scope & deliverables. Review progress regularly & establish and monitor effective design performance metrics	
Resources				
Insufficient OPG design resources available	Delay project schedule & milestones.	**High**	Design will be contracted out to external agency. OPG Projects Design have committed to provide DTL support for this project.	**Low**
Availability of qualified vendors to perform design and subsequent implementation	Delay in issuing contract due to need to amass variuous interfacing risks and vendor qualification issues and contracting language.	**Medium**	Obtain OPEX from other OPG projects of similar nature, early involvment with Supply Chain and various other deparments or potential vendors and the associated contracting strategies.	**Low**
Technical				
Meeting seismic requirements	Increase cost to the project due to unkown civil upgrade to meet the seismic requirement.	**High**	Seismic qualification considered as part of conceptual study. Seismic qualification requirements to be included in Preliminary Design	**Low**
Discoveries from geotechnical analysis of soil	Delay and added cost to the project due to the prefered site not being suitable for building addition. Increase cost to the design and installation to meet the requirements identified	**Medium**	Test drill site to determine the soil composition prior to completing preliminary engineering to ensure the design takes this into account. Method & cost to implement corrective actions will be challenged & documented.	**Low**
Legacy issues on Design, and interface issue with other related D2O prpjects	Re-eingineering may be required if there are legacy and interface issues with systems that the project is modifying. This would add scope to the project which may cause delays and will increase project costs	**Medium**	Site walkdowns have been completed. Complete drawing review on system impacted during Preliminary Engineering, and ensure there are open dialog with other projects.	**Medium**
Increased scope of work due to discovery work	Changes in scope will delay the schedule and add cost to the project.		Drawing rieview has been conducted to identify any possible underground services that may require relocation. Field survey to be completed during Preliminary Engineering	

Regulatory				
Regulatory approvals (CNSC & TSSA) requiring more time then anticipated	Delay in project & potential cost impact to contract	**Medium**	Identify required time allowance in project schedule. Incorporate approved time in contracting strategy. Review OPEX with other similar projects	**Low**
Environmental				
n/a				
Health & Safety				
n/a				
Investment				
Cost benefit information obtained from stakeholders was not correct	NPV and IRR results may be less optimistic than calculated	**Medium**	Line management was involved in provoding the information based on historical perfomance of the system	**Low**
Inability to recover investment such as TRF production is unreliable	Insufficient time to recover capital investment before stations' end of life	**Medium**	The current NPV and IRR indicate a positive return on investment before stations' end of life. Impelement ongoing TRF improvement initiative to improve reliability.	**Low**
Early end of life of DNGS or TRF	Insufficient time to recover capital investment if end of life is earlier then currently forecast	**Low**	Using the current forecast of DNGS end of life date the current NPV and IRR indicate a positive return on investment before stations' end of life	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
TBD in Next Release	TBD in Next Release Choose Year	TBD in Next Release Choose Year	Rumina Velshi

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

AECL – Atomic Energy Canada Limited
AFS - Available for Service
CNSC - Canadian Nuclear Safety Commission
DG – Downgraded
D_2O – Heavy Water
DIOTS – Darlington in/Out Transport System
EC - Engineering Change
EOL - End of Life
HWMB – Heavy Water Management Building
IXCU - Ion Exchange Clean Up
LLD – Low Level Drain
NPV - Net Present Value
OP&P - Operating Policies and Principles
PHT - Primary Heat Transport
RFP – Request For Proposal
RG – Reactor Grade
SCO – Station Containment Outage
S&I - Storage and Inventory
SUP – Station Upgrader
TDO – Tritiated Heavy Water
TOC – Total Organic Carbon
TRF – Tritium Removal Facility
TSSA – Technical Specification
UV – Ultra Violet
VBO – Vacuum Building Outage

Appendix "B" Project Funding History

Choose Release Type	Month	Year	Previous Releases (incl contingency) Cumulative Values 2004	2005	2006					Later	Total
None											0
											0
											0
											0
											0
											0
											0
											0
LTD Spent											0

Comments:

The current estimate of $36.4M (including contingency and interest) is a conceptual quality estimate (estimate band of +60% to -25%), and has an estimated available for service (AFS) date in Q4 of 2010. The estimate has been independently verified by Helyar ($35.7M). The variance between the two project cost estimates is due to labour escalation each year and additional Project Management resources are required to complete close-out in 2011 which were not included in the Helyar estimate. Given that the estimate is performed based on conceptual information, there is a risk that this estimate may escalate (refer to section 6 Risk Table).

Project funding in the amount of [redacted](excluding contingency) is listed in the current approved Business Plan 2007 to 2011. The variance to the business plan will be addressed through the portfolio management process. There is $0 capital spending released today to this project.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

OPG staff will provide project management & support role during design and implementation
Material cost assumptions based using class 3 tanks, hangers, piping and associated equipment
Design and installation work will be contracted out

Financial Assumptions:

Escalation rate of 2% on revenues
Escalation rate of 3% on employee wages
See attached for assumptions regarding NPV calculations

Project / Station End of Life Assumptions:

Darlington end of life is 2019

Energy Price / Production Assumptions

N/A

Operating Cost Assumptions

New operating costs are negligible.
Cost to upgrade D_2O [redacted]
Cost to lease D_2O from [redacted]

Other Assumptions:

OPG to provide unrestricted access to work area
All work is within the secured area with incumbent restrictions
All Nuclear grade materials purchased by OPG

Project Name 16 - 31555

Partial Release Business Case Summary D-BCS-38000-10001-R001

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr	This Release 2007	This Release 2008	Future Release 2008	Future Release 2009	Future Release 2010	Future Release 2011	Later	Total
Project Management (OPG)		546	390	454	1,020	948	152		3,510
Engineering & Drafting (OPG)		379	195	236	280	679	226		1,995
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	-	1,872	1,728	3,992	13,253	14,938	600	-	36,383
2006-2010 Business Plan		1,500	1,800	6,700	4,700	5,000			19,700
Variance to Business Plan	-	(59)	(481)	(3,605)	5,559	6,628	458	-	8,500
Committed Cost		-	-	-	-	-	-		-
Inventory Write Off Required		-	-	-	-	-	-		-
Spare Parts / Inventory		-	-	-	-	-	-		-
Total Release (excl contingency)	-	1,441	1,319	3,095	10,259	11,628	458	-	28,200
Total Release (incl contingency)	-	1,872	1,728	3,992	13,253	14,938	600	-	36,383

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	Zero to Minimal		Quality of Estimate	Conceptual + 60% to - 25%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Jan 2007.

Reviewed By: Nov 8/06

Stephanie Tham
Project Manager

Date:

Approved By: Nov 3/06

Peter Floyd
Eng & Mods Manager (Strat IV)

Date:

Project Name 16 - 31555

Partial Release Business Case Summary D-BCS-38000-10001-R001

Attachment "B" **Project Variance Analysis**

Capital	LTD Nov 2006	Choose One: Last BCS N/A N/A	Choose One: This BCS Nov 2006	Variance	Comments
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material	[redacted]				
Installation – PWU, BTU	[redacted]				
Contract - Design	[redacted]				
Contract - Installation	[redacted]				
Contract - Other	[redacted]				
	[redacted]				
	[redacted]				
Interest (Capital Project Only)	[redacted]				
Project Costs (excl contingency)	[redacted]				
General Contingency	[redacted]				
Specific Contingency	[redacted]				
Project Costs (incl contingency)	**0**	**0**	**0**	**0**	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**0**	**0**	**0**	**0**	
Total Release (excl contingency)	**0**	**0**	**0**	**0**	

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
30	NOV	2006	Developmental BCS Approved
01	FEB	2007	Project Start
10	May	2007	Major PO/Contract Award - Design Contract
19	SEP	2007	Long Lead Material Identified
01	NOV	2007	Partial BCS Approved
22	NOV	2007	Preliminary Design Complete (40%)

A Project Execution Plan (PEP) will be approved by May 2007

Comments:

Attachment to D-BCS-38000-10001-001
NPV Calculation Assumptions for Revenue & OM&A Costs

Category	Cost	Rational
CAPITAL EXPENDITURES	$36,388,000	**Cost to build HWMB addition, install 400Mg of new tanks, drum storage area & drum pressure testing equipment. (including [redacted] contingency & [redacted] interest)**
OM&A Costs		
New Drum Purchases	[redacted]	Drums assumed @ [redacted] /drum -> 300 drums x [redacted] over 5 years [redacted]
Cost to ship 100 Mg of Moderator D2O off site	[redacted]	Cost to ship 100 Mg of D2O and have it stored at [redacted] to accommodate a Moderator Drain estimated @ once every 2 years
Cost to re-upgrade D2O in the event of downgrading reactor grade D2O.	$1,500,000	20% chance of downgrading event of 100 Mg Eliminate the practice of using S&I or DIOTS tanks to store downgraded D2O during TRF & SUP outages
Cost to borrow Low Ci D2O from AECL to provide PHT make-up during SCO/VBO.	[redacted]	[redacted] @ [redacted] = [redacted] Lease for [redacted] ays (2003) = [redacted] Risk of sufficient overpacks available to ship this water Potentially occur every SCO &/or VBO
Operator time lost due to moving drums to make space	$64,000	800hrs @ 80/hr=64000
Cost to pressure test drums off site	[redacted]	[redacted] x 200 drums/year = [redacted]
ADDITIONAL/NEW REVENUE		
Bruce Power	[redacted]	Detritiation services for new Units starting @ [redacted] @ [redacted]
External Business (excess capacity)	[redacted]	Excess capacity of TRF [redacted] @ $ [redacted] Provide detritiation services to [redacted]
Additional sales	[redacted]	Import more drums of D2O from external customers [redacted] cleanup D2O and sell to [redacted] for loss makeup [redacted]

Main Control Room HVAC 16 - 33293

Superseding Business Case NK38-BCS-73920-10002-R000

1/ RECOMMENDATION:

Approval is requested to reduce the scope of the planned modifications to the Main Control Room (MCR) HVAC system, to focus on absolute requirements to meet the project objectives, and remove optional elements that would otherwise drive costs beyond the previously released amount of $11M. No additional funding is requested under this superseding BCS.

The original business objective for this project was to address the following deficiencies in the MCR HVAC system:

- High temperature excursions that threatened reliable operation of the units
- Health and Safety concern with the lack of proper filtration and humidification

Much of the work to meet these objectives has been completed to date, and real benefits have been confirmed in the current MCR environment.

A Full Release BCS releasing $6M for this project was approved in May 2001. Subsequently in July 2003, a Superseding BCS for a total release of $11M was approved. By June 2005, it became apparent that up to an additional $3M would be required to fully complete all required and optional elements of the project scope.

To mitigate this cost increase, a review of the project was initiated to separate the absolute requirements (needs) from the optional requirements (wants). As the result of the review, in April of 2006, the Darlington Project Approval Committee approved a plan to reduce the number of modifications, thereby keeping the estimated cost of the project within the currently released amount of $11M. (See the Background section for a summary of the changes to this project). The reduced scope will still address the business objectives of the Main Control Room HVAC project.

The Life-to-Date actual cost of the project is $9.750M vs. $11.0 M full release. The remaining field work and closeouts in this proposal are well understood and defined. The risks associated with this plan of action have been assessed and mitigated to provide assurance that the remaining funds will be sufficient to complete the reduced scope of this project.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	Superseding	9,750	983	237	30				11,000
Requested Now	Superseding								-
Future Funding Req'd	None								-
Total Project Costs		9,750	983	237	30	-	-	-	11,000
Other Costs									-
Ongoing Costs									-
Grand Total		9,750	983	237	30	-	-	-	11,000

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Sustaining	Capital			

Submitted By:

Wayne Robbins
Senior Vice President, Darlington Nuclear

Date: 2007-05-23

Finance Approval:

Jim Beech
Vice President, Nuclear Finance

Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Tom Mitchell
Chief Nuclear Officer

Date:

2/ BACKGROUND & ISSUES

The project originated in late 1999 as a post construction clean up work order and continued under OM&A Project # 38276 for definition and scoping and for certain maintenance activities to ensure continued operation of the major system components.

It was soon determined that replacement / installation of major equipment such as cooling coils, humidifiers and filters were essential to address the issues related to temperature, humidity and air quality in the Main Control Room (MCR) and the adjacent Computer Equipment Rooms (CER).

In May of 2001 a Full Release BCS was approved for $6,040k for the aforementioned modifications as well as provision of required redundancy for Glycol System RV and Pump Seal Supply (absolute requirements) and major modifications to the ducting, systems and controls and a comprehensive monitoring and diagnostic system (optional requirements).

In July of 2003 a cost variance Superceding BCS was approved for $11,000k. The variance in cost was mainly due to low original estimates. (A full explanation of variances was provided in that BCS).

In June of 2005 the balance of the project scope was reviewed and the forecast to complete was estimated to be $14,000k excluding contingency. Upon this estimate the project status in the Major Projects Status Report turned "Red" indicating major project cost and schedule issues. To recover the project back to "green" status a project recovery process was initiated. In this process the balance of the scope of the project was analyzed against the following absolute requirements:

- Temperature and Relative Humidity
- Address Toxic Gas report by positive blocking of the Maximum (90%) Air Dampers
- Redundant RV and Pump Seal supply to resolve the singleton issues associated with these components – failure of any of these singletons would have resulted in MCR HVAC shut-down

At present the major modifications (cooling coils, humidifier and filter replacements) and the Glycol System redundant RV and Pump Seal supply have been completed. Temperatures have decreased in the target areas and Relative Humidity values have increased especially during dry winter months. The new filters are performing as expected and the ergonomic and employee health and safety issues with the old electrostatic filters have been eliminated.

Those elements of the remaining scope which met the above requirements were classified as "needs" or absolute requirements and the rest as "wants" or optional requirements. In April of 2006, the station Project Approval Committee (PAC) accepted the following recommendations:

- Complete positive blocking of the Maximum (90%) Air Dampers
- Replace Minimum (10%) Air Dampers
- Review Temperature and Relative Humidity measuring instruments in the Control Room and provide field instruments if needed

Subsequent to PAC meeting, the requirements for Temperature and Relative Humidity measuring in MCR and CER were reviewed and it was determined that additional field instruments were not warranted.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended)		Alt 2 Delay	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost				
Revenue							
OM&A							
Capital	(9,282)	(6,281)	(540)				
NPV (after tax)	(7,369)	(5,116)	(420)				
Impact on Economic Value (IEV)	N/A	2,253	6,949				
IRR%	N/A	N/A	N/A				
Discounted Payback (Yrs)	N/A	N/A	N/A				

Status Quo - Not Recommended

Continuing with the full scope and requesting an additional $3.0M is not recommended. In April of 2006 the Station Project Approval Committee approved the reduce scope to meet the absolute requirements only, and complete the project within the previously-approved release of $11M.

Alternative 1 - Complete the Reduced Scope and Close-out - Recommended

It is recommended that the scope be reduced to the following absolute requirements:

- Disable free cooling feature by capping the maximum outside air dampers, this will address the requirements set forth in Senior Vice President's memo to CNSC: "Darlington NGS – Safety Report Analysis Update: Toxic Corrosive Chemical Rail Line Accident", dated Oct 12, 2004.
- Replacement of the minimum outside air dampers.
- Documentation clean-up and close-out – significant engineering effort is required to revise design documentation associated with the reduced optional scope and to close out the project.

A rigorous scope analysis was done in 2005 and recommendation was made to eliminate the optional requirements from the scope of the project. The elements of the scope that have been eliminated are of discretionary nature, as approved by the DNGS PAC in April 2006.

Alternative 2 - Delay Project - Not Recommended

N/A

Alternative 3 – N/A - Not Recommended

Alternative 4 – N/A - Not Recommended

Alternative 5 – N/A - Not Recommended

4/ THE PROPOSAL

1) Complete the following scope within the remaining funds of the project:

- Disable free cooling feature by capping the maximum outside air dampers, to address the requirements set forth in Senior Vice President's memo to CNSC: "Darlington NGS – Safety Report Analysis Update: Toxic Corrosive Chemical Rail Line Accident", dated Oct 12, 2004.

- Replace the minimum outside air dampers.

- Complete the documentation clean-up (revise design packages for the optional scope) and close-out the project.

2) Delete the following scope:

- Ducting Systems and Control Modifications
- Comprehensive Monitoring System
- Removal of obsolete equipment (tanks and pumps).

The project will be closely monitored and controlled to ensure that the remaining scope is completed within the approved funds.

5/ QUALITATIVE FACTORS

The main qualitative factor of this initiative (cost growth reduction) is to drive a business type behaviour in the organization and encourage all the project teams/stakeholders to limit the project scope on the absolute requirements of the station

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Cost increase - negligible risk	Cost growth may cause project costs to exceed release.	**Medium**	The reduced scope is well defined. The estimate is based on commitments from supporting departments and input from third party estimating group. Approx $100k contingency is still available.	**Low**
Scope				
Scope is defined and 90% designed. Risk of scope growth is low	Scope growth may cause cost increases and schedule extensions to exceed the release limits.	**Medium**	The scope is limited to blocking max outside air dampers and associated exhaust dampers, replacement of the minimum air dampers and documentation clean-up. The risk of scope growth is negligible and approx $100k is still available within current release for any unforeseen work.	**Low**
Schedule				
Station emerging priorities.	Emerging Station priorities may cause schedule extensions resulting in slippage of milestone dates in release.	**Medium**	The schedule is based on resource commitments, (e.g., Design, Field Engineering and installation contracts), Work Management procedures with some float. WOs are scheduled on IPG Plan. This will minimize schedule risk.	**Low**
Resources				
Re-allocation of key resources such as design and field engineering to other projects.	Key resources not available when required may cause schedule extensions and cost growth.	**Medium**	Commitments obtained from key resource providers. The project will maintain close communication with IPG to ensure the priority is maintained.	**Low**

Technical				
Relative Humidity target levels may not be achievable.	Possible scope growth may cause cost increases and schedule extensions to exceed the release limits.	**Medium**	Agreement reached with Design and key stakeholders to revise RH targets to reflect achievable humidity levels.	**Low**
Regulatory				
		N/A		
Environmental				
		N/A		
Health & Safety				
Conventional Heath & Safety risks during implementation.	Conventional Heath & Safety risks will be present during the implementation of the project but will be closely monitored and controlled.	**Low**	COMS and JSA as well as adherance to all station safety procedures will eliminate/ minimize this risk.	**Low**
Investment				
		N/A		

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Mar 2008	Jun 2009	Performance Engineering

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Maximum Air (90%) Dampers: -leakage rate	Max Air Dampers are jumpered closed but not capped, leakage rate unknown	Max Air Dampers covered with zero leakage	Testing as per design documents	Field Engineering/ Performance Engineering
2.	Minimum Air (10%) Dampers: -leakage rate -closing time	-leakage rate unknown -closing time <20sec	-leakage rate 1% or less -closing time <20sec	Testing as per design documents	Field Engineering/ Performance Engineering
3.	Temperature	Exceeds 22 Deg C	20 to 22 Deg C	Testing as per design documents	Field Engineering/ Performance Engineering
4.	Relative Humidify (RH)	Below 20% RH	Target minimum 35%, maximum 45% RH	Testing as per design documents	Field Engineering/ Performance Engineering
5.	Air Filtration	Pre-filtration only. Electrostatic agglomerator not functional. Ingress of poorly filtered air into MCR and CER.	Filtration efficiency of 90% to 95% as per manufacturer test reports. Pressure drop during operation less than 625 Pa.	Efficiency as per test reports verified by Design. Pressure drop measured during testing and commissioning.	Field Engineering/ Performance Engineering

Appendix "A" **Glossary** (acronyms, codes, technical terms)

CER	Computer Equipment Room
AFS	Available for Service
HVAC	Heating Ventilation & Air Conditioning
MCR	Main Control Room
RV	Relief Valve
BCS	Business Case Summary
PAC	Project Approval Committee
RH	Relative Humidity
PIR	Post Implementation Review
ASHRAE	American Society of Heating, Refrigeration & Air Conditioning Engineers

Appendix "B"

Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2001	2002	2003	2004	2005	2006	2007	Later	Total
Full	May	2001	2,130	1,840	2,070						0
Superseding	Jul	2003		4,037	1,800	2,830	2,333				6,040
Superseding	Jan	2007									11,000
		Choose						9,750	983	267	11,000
		Choose									0
		Choose									0
		Choose									0
											0
LTD Spent	Dec	2007	2,473	1,564	1,651	1,836	1,780	446			9,750

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

N/A

Financial Assumptions:

Interest = 6%

Project / Station End of Life Assumptions:

2018

Energy Price / Production Assumptions:

N/A

Operating Cost Assumptions:

N/A

Other Assumptions:

N/A

Main Control Room HVAC 16 - 33293

Superseding Business Case NK38-BCS-73920-10002-R000

Attachment "A"

Project Cost Summary

$000's Capital	LTD Prior Yr 2006	This Release 2007	This Release 2008	This Release 2009				Later	Total
Project Management (OPG)	1,306	64	30	4					
Engineering & Drafting (OPG)	481	245	137	26					1,404
Material	500	255							889
Installation -- PWU, BTU	1,210	129							755
Contract - Design	4,905								1,339
Contract - Installation	331	140							4,905
Contract - Other	5		40						471
									45
									-
Interest (Capital Project Only)	1,012	70	5						-
Project Costs (excl contingency)	9,750	903	212	30	-	-	-	-	1,087
General Contingency		80	25						10,895
Specific Contingency									105
Project Costs (incl contingency)	9,750	983	237	30	-	-	-	-	-
2007-2011 Business Plan		1,039	-						11,000
Variance to Business Plan	9,750	(136)	212	30	-	-	-	-	1,039
Committed Cost									9,856
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	9,750	903	212	30					-
Total Release (incl contingency)	9,750	983	237	30	-	-	-	-	10,895
									11,000
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	Up to - 40%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	No	Budgetary Quote(s)	Yes	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in place	Yes	Competitive Bid	No

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by May 2007.

Reviewed By:

24 Apr 2007

Tom Cvitkovic
Project Manager

Date:

Approved By:

25 Apr 2007

Terry Chong
Eng & Mods Manager (Strat IV)

Date:

Main Control HVAC 16 - 33293

Superseding Business Case NK30-BCS-73920-10002-R000

Attachment "B" **Project Variance Analysis**

Capital	LTD Dec 2006	Choose One: Last BCS Jul 2003	Choose One: This BCS Jan 2007	Variance	Comments
Project Management (OPG)	1306	603	1404	801	Low initial estimate, schedule extension
Engineering & Drafting (OPG)	481	773	889	116	Low initial estimate, schedule extension
Material	500	524	755	231	Low initial estimate
Installation – PWU, BTU	1210	2286	1339	-947	Assignment of work to external contractor, scope reduction
Contract - Design	4905	4650	4905	255	Low initial estimate
Contract - Installation	331		471	471	Assignment of work to external contractor
Contract - Other	5		45	45	Air Testing Contractor
				0	
				0	
Interest (Capital Project Only)	1012	564	1087	523	Schedule extension
Project Costs (excl contingency)	**9750**	**9400**	**10895**	**1495**	
General Contingency		**1600**	**105**	-1495	
Specific Contingency				0	
Project Costs (incl contingency)	**9750**	**11000**	**11000**	**0**	
Committed Cost					
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
				0	
Total Release (incl contingency)	**9750**	**11000**	**11000**	**0**	
Total Release (excl contingency)	**9750**	**9400**	**10895**	**1495**	

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
18	05	2007	(PTA) Work Package Assessment Complete
13	08	2007	(SOI) Start of Installation Dampers
14	01	2008	(AFS) AFS Damper Mods Complete
19	02	2008	(DCP) DCP Rev03 - Complete
28	04	2008	(AFS) Final AFS
13	03	2009	(PCM) Project Complete

A Project Execution Plan (PEP) will be approved by Jun 2007

Comments:

Approved PEP (NK38-PEP-73920-10001) will be revised by June 2007.

DARLINGTON USED FUEL DRY STORAGE PROJECT – RELEASE #5 – IN-STATION MODIFICATIONS – FUEL FACILITY AUXILIARY AREA (FFAA) - WEST

1. RECOMMENDATION:

Approval is requested for a partial release of $21.3M, for the installation of equipment and modifications to the Fuel Facility Auxiliary Area (FFAA) – West at the Darlington plant, and the acquisition of long-lead material items required for FFAA – East. Subject to approval of this current release, and including previous funding approval of $72.5M, the total releases to date for the Darlington Used Fuel Dry Storage Project would be $93.8M. The total project cost is currently estimated at $108.2M.

The In-Station Modification work initiated to date includes the detail design and CNSC approvals work associated with the fuel facility auxiliary areas. The current cost estimate for the In-Station Modifications is $50.3M, funded from the capital program. The expected in-service date for the FFAA – West has been revised to April 2008. A final funding release for the FFAA - East is planned for September 2007. The current estimate for the final release is $14.4M. The expected in-service date for the FFAA – East has been revised to April 2009.

The Dry Storage Facility work initiated to date includes the regulatory approvals, detail design and construction of the facility. A total of $57.9M has been released for this work, funded from Nuclear Waste Provisions. The expected in-service date for the Dry Storage Facility is 2007.

This project is categorized as a *Sustaining* investment, required for the continued operation of the Darlington plant. The project is listed in the approved business plan for 2006. The project cash flows are provided in Appendix 1.

2. SIGNATURES

Submitted by:

K G Nash Jun 15/06
Ken Nash Date
Vice-President,
Nuclear Waste Management Division

Recommended by:

June 14, 2006
Gregory Smith Date
Senior Vice-President, Darlington

Recommended by:

Jun 19/06
Pierre Charlebois Date
Chief Nuclear Officer

Financial Approval by:

June 29/06
Donn Hanbidge Date
SVP & Chief Financial Officer

Line Approval per O.A.R. Element 1.1:

July 7/06
Jim Hankinson Date
President and CEO

3. BACKGROUND AND ISSUES

Used nuclear fuel arising from Darlington Nuclear Station is currently stored in east and west water pools (also referred to as *irradiated fuel bays*) located inside the station. The west water pool is projected to become full in February 2009, and the east water pool in 2010. The purpose of the Darlington Used Fuel Dry Storage Project is to provide additional used fuel interim storage to allow continued operation of the station.

The total project consists of modifications to the station water pools to allow DSC's to be loaded, design and construction of a DSF, and upgrades to site roads to allow the DSC's to be transferred to the DSF. The DSF approved for construction by CNSC comprises a processing building where the DSC's are welded, x-rayed and prepared for storage, and up to three storage buildings with a total capacity of 1,500 DSC's. This capacity, together with existing water pool storage, is sufficient to accommodate used fuel from a 40-year operating life for all four Darlington reactors. It is projected that the second and third storage buildings will be needed by 2015 and 2023, respectively and at a cost in the order of $10M to $15M per building.

The original target in-service date of 2007 allowed for a one-year contingency in project schedule, plus a one-year buffer capacity in the Darlington water pools. Both OPG and Bruce Power operate with a minimum of one year water pool buffer capacity to accommodate unforeseen operating and production problems in water pools, the dry storage facility (DSF), and at the dry storage container (DSC) manufacturing plant. It is currently projected that the first fuel will be moved from the west bay in April 2008, ten months ahead of its projected fill date.

Dry storage at Pickering Waste Management Facility (PWMF) became operational in 1995, and at the Western Waste Management Facility (WWMF) (located at the Bruce Nuclear Site) in 2002. All fuel bundles are stored in standard DSC's. Each DSC holds 384 fuel bundles and weighs 70 tonnes. It is planned to use the same dry storage container design at Darlington and to use similar processing equipment in the DSF. A total of 550 DSC's are currently in storage. Operational experience has been excellent.

The release history/plans for the different phases of this project follow:

I) **Work In Progress/Completed to Date**	
Jan 2001	A development release of $2.4M was approved under the authority of the Vice President, Nuclear Waste Management Division to submit a Comprehensive Environmental Assessment (EA) Study to the Canadian Nuclear Safety Commission (CNSC). EA approval was granted in November 2003 for the Dry Storage Facility and up to three storage buildings.
Nov 2002	A development release of $5.4M was approved under the authority of the Vice President, Nuclear Waste Management Division (bringing the total release to $7.8M) for preliminary engineering for the Dry Storage Facility and In-Station Modifications, and to prepare and submit an application to the CNSC for a Construction Licence. The construction licence was granted in August 2004.
Jun 2004	A partial release of $12.2M was approved under the authority of the OPG Board of Directors (bringing the total release to $20.0M) for the completion of detail design and specifications of the in-station modifications, together with CNSC approval. This work has been completed.
Mar 2005	A partial release of $52.5M was approved under the authority of the OPG Board of Directors (bringing the total release to $72.5M) for the detail design and construction of the Dry Storage Facility. The work scope includes the processing building, one storage building for 500 DSC's in a new security protected zone, and upgrade of the roadways at the Darlington site. The work is targeted for completion by the end of 2007.

II) **Work to be Done Under this Release**	
Mar 2006	A partial release of $21.3M is the subject of this business case (bringing the total release to $93.8M), and comprises the installation of equipment and modifications to the Fuel Facility Auxiliary Area (FFAA) – West, and the acquisition of long-lead material items required for FFAA – East. The FFAA – West is now targeted for service by April 2008.

III) Future Work	
Sep 2007	A final project release of $14.4M (bringing the total release to $108.2M) will be sought to complete the installation of equipment and modifications to the FFAA – East. The FFAA – East is now targeted for service in April 2009.

4. ALTERNATIVES

The previous releases for this project established the scope and direction for interim dry storage at Darlington.[1, 2, 3, 4] Dry storage is the preferred method of providing additional capacity. The total project cost is estimated at $108.2M, with an in-service date of April 2009. The completion of the Darlington Used Fuel Dry Storage Project will allow the Darlington Nuclear Generating Station to continue to operate beyond 2009.

5. THE PROPOSAL

This current phase of the overall dry storage project will allow for the installation of equipment and modifications to the Fuel Facility Auxiliary Area (FFAA) – West, and the acquisition of long-lead material items required for FFAA – East. The cost estimate for this phase is based on a competitively-bid construction contract. The overall project estimates are summarized in Appendix 2.

This phase of work is expected to start in July 2006, with the following milestones:

- Jul 2006 – All long-lead material item purchase orders placed for both fuel bays; and award major construction contract
- Sep 2006 – Start of services relocation work to FFAA-West
- Nov 2006 – Start of major construction/construction zone set-up
- Mar 2008 – Complete FFA-West installation
- Apr 2008 – FFAA – West available for service complete.

[1] Business Case Summary, Darlington Used Fuel Dry Storage Project – Development Release for Environmental Assessment Submission, January 9, 2001

[2] Business Case Summary, DUFDS Project – Development Release for EA Approval, Construction License & Preliminary Engineering, November 26, 2002

[3] Business Case Summary, Darlington Used Fuel Dry Storage Project – Release #3 – Detailed Engineering of In-Station Modifications, June 2004

[4] Business Case Summary, Darlington Used Fuel Dry Storage Project – Release #4 – Detailed Design & Construction of Dry Storage Facility, March 24, 2005

6. QUALITATIVE FACTORS

The use of DSC's is consistent with the long-term management recommendations submitted by the Nuclear Waste Management Organization to the federal government.

A Sustainable Energy Development Impact Assessment was conducted for the Western Used Fuel Dry Storage in 2000. For a similar installation, the assessment concluded that the approach of using DSC's has the least impact on the environment when compared to the assessed alternatives.

7. RISKS

7.1 Current Release Risks

Modification of Water Pools

The current estimate is based on detailed design work conducted by an experienced Canadian nuclear engineering company, with a competitively-bid construction contract. Because of a substantive number of outstanding design considerations and logistical complexities, the equipment and modification work will be conducted in two phases. The lessons learned from the west pool can be used to finalize the design and funding requirements for the east pool. An overall contingency factor of 20% has been applied to this phase of the project cost estimate. A risk matrix summary is included in Appendix 3.

7.2 Other Risks

Construction of the Dry Storage Facility

A turnkey design-build contract has been awarded, and is progressing on schedule and within budget. A 95% design stage has been achieved and several risks eliminated. There is a high level of confidence that the facility will be completed within the approved funding of $52.5M (as approved by Release #4) for this part of the project. The Dry Storage Facility is expected to be available for service in accordance with the original schedule of 2007. As of April 2006, $15.8M has been spent on the Dry Storage Facility.

Facility Location

The location of the Dry Storage Facility was previously assessed for potential conflict with new-build nuclear units on the Darlington site. It has been confirmed that it should be possible to locate up to four units on the site without encroaching on the DSF. The location of future dry storage buildings will be dependent on any plans for additional new-build nuclear units.

8. POST IMPLEMENTATION REVIEW PLAN

- A Comprehensive Post Implementation Review (PIR) will be carried out within one year of the project in service of both Fuel Facility Auxiliary Areas (by April 2010), consistent with the corporate PIR Procedure. It will be conducted by an Independent Team with the Team Leader appointed by the Project Approval Authority.

- The Comprehensive PIR will be an independent and systematic performance evaluation of the project for these objectives:

  - Assess the realization of the project benefits consisting of:

    i. The detailed design and specification of the in-station modifications, and

    ii. The installation of equipment and modifications to the Fuel Facility Auxiliary Areas,

  - Review project plan, implementation and operational performance.

  - Review BCS - major assumptions, economic and financial evaluation looking back from results, for future decisions.

  - Review project risk management.

  - Identify over-all lessons learned, in addition to those documented by the project team, for future improvement.

Appendix 1 – Project Cash Flows & Business Plan

The project cash flows and approved business plan funding are provided in the table below. The additional funding required to implement the In-Station Modifications can be accommodated within OPG Nuclear's approved business plan envelope.

In-Station Modifications (Capital)

Year →	2001 – 5	2006	2007	2008	2009	Total
Current Total Estimate ($M)	9.5	8.1	18.3	13.4	1.0	50.3
Current Estimate w/o Contingency ($M)	9.5	7.1	15.6	11.8	0.9	44.9
Business Plan ($M)	9.5	19.1	12.0	1.2	-	41.8
Variance ($M)	-	(12.0)	3.6	10.6	0.9	3.1

Dry Storage Facility (Nuclear Waste Provisions)

Year →	2001 – 5	2006	2007	2008	2009	Total
Current Estimate ($M)	12.4	20.3	25.2	-	-	57.9
Business Plan ($M)	12.4	21.5	25.2	-	-	59.1
Variance ($M)	-	(1.2)	-	-	-	(1.2)

Appendix 2

Darlington Used Fuel Dry Storage Project – Cost Estimates

($k)	Y/E 2005	2006	2007	2008	2009	Total
1. IN-STATION MODIFICATIONS						
Owner's Agent	1,530	473	317			2,320
Design Agency	3,108	610	669			4,387
Licencing Support	234	82				316
Other Contracts	2,473	183	260			2,916
OPG Project Management/Support	1,466	1,879	2,646			5,991
OPG DSF/Calandria Road Support		110				110
Construction Labour		1,411	6,591			8,002
Material		215	3,192			3,407
Outstanding Claims/Contract Scope		1,496	322			1,818
Interest	738	689	1,531			2,958
Contingency		992	2,735			3,727
Sub-total	**9,549**	8,140	**18,263**			**35,952**
Final Release - East Fuel Bay				13,368	983	14,351
IN-STATION MODIFICATIONS ESTIMATE	**9,549**	8,140	**18,263**	13,368	983	**50,303**

In-Station Modifications Estimate

Approved by: [signature]
Ray Balachorek, Project Manager, Design Projects

Date: May 30, 2006

2. DRY STORAGE FACILITY	12,376	20,262	25,232	-	-	57,870

3. PROJECT TOTALS	21,925	28,402	43,495	13,368	983	108,173

Appendix 3 - Risk Summary

Reference	Risk Description/ Consequence	Probability	Impact	Mitigation Measures	Contingency Exposure ($k)	Contingency Probability	Contingency Total (k$)
1	Schedule - West fuel bay fills faster than predicted. Reduced storage buffer could impact unit operation, with potential deretings.	M	H	Manage the buffer by maintaining preferential fuel deliveries to the FFAA-East. Reconfiguration of the fuel bays will also increase buffer.	-	L	-
2	Schedule - Regular or emergent fuel handling/station work requires the project to vacate the work area. Potential schedule delays of up to 3 days per month.	M	M	Sign coordination agreement between the station and the project.	1,980	L	595
3	Schedule - Late delivery for long lead material items, resulting in delay for FFAA-West completion.	M	M	Purchase Orders for long lead items to ba issued immediately following project release.	800	L	200
4	Cost - Installation costs higher than estimated due to sole source or schedule compression.	H	M	Contract requests fixed price, and negotiation with 2 lead bidders.	4,400	L	660
5	Cost - Project costs increase due to field changes, and late design package approval. Field changes could cause up to 2 days per week schedule loss/cost increases.	H	M	Walkdown of design to identify field changes. Implement an efficient field change approval process.	3,080	L	770
6	Cost - Concrete has radioactive contamination, ceusing a major delay for handling radioactive waste, and higher waste costs.	L	M	Identify contamination ahead of construction, together with contingency process for handling radioactive waste.	1,600	L	400
7	Resourcing - Future contractor labour shortage occurs, resulting in inability of contractor to maintain schedule and quality.	M	M	Contract award to secure resources.	550	L	138
				SUB-TOTAL ▶			2,763
8	Unforeseen miscellaneous items (unknown unknowns).	M	M	Communication and project meetings.	964	1	964
				TOTAL ▶			3,727

ONTARIO POWER GENERATION	Document Number: 00044-BCS-00120.3-00003	Revision: R0	Page: 1 of 8
	Darlington Used Fuel Dry Storage Facility Project: In-Station Modifications (Fuel Facility Auxiliary Area (FFAA) East) Business Case Summary for Final Release of Funds		

1. RECOMMENDATION:

Approval is requested for a final release of $11.9M for installation of equipment and modifications to the Darlington Fuel Facility Auxiliary Area (FFAA) East, in order to complete the Darlington Used Fuel Dry Storage (UFDS) Project. This release includes the installation of equipment and modifications to the Darlington FFAA East (also described as water pools, or irradiated fuel bays).

Project funding of $93.8M has been previously approved for the detail design, regulatory approvals, installation of equipment and modifications to the FFAA West, and the acquisition of long-lead material items required for Fuel Facility Auxiliary Area – East; as well as the regulatory approvals, detail design and construction of the Darlington UFDS Facility. The total project cost estimate is $105.7M, which is $2.5M less than the original estimate provided to the Ontario Power Generation (OPG) Board of Directors in 2004 at the time of the first release of funds requiring their approval.

This project is categorized as a Sustaining investment, required for the continued operation of the station past 2009. Funding is included in the approved business plan consistent with this proposal. Project cash flows are provided in Appendix B.

2. SIGNATURES

Submitted by:

K. E. Nash 9-Nov-2007

K. Nash Date
Senior Vice-President,
Nuclear Waste Management

Recommended by:

12-18-07

W. Robbins 2007-12-21

W. Robbins Date
Senior Vice-President,
Darlington

Recommended by:

T. Mitchell 18 JAN 08

T. Mitchell Date
Chief Nuclear Officer

Recommended by:

Jan 21/08

P. Charlebois Date
Executive Vice-President
& Chief Operating Officer

Financial Approval by:

D. Hanbidge Feb 8/08

D. Hanbidge Date
Senior Vice-President
& Chief Financial Officer

Line Approval per OAR Element 1.1

J. Hankinson Feb. 11/08

J. Hankinson Date
President
& Chief Executive Officer

3. BACKGROUND & ISSUES

Used nuclear fuel arising from Darlington Nuclear Station is currently stored in the east and west irradiated fuel bays (water pools) located inside the station. The west water pool will become full in 2009 and the east in 2010. The purpose of the Darlington UFDS Project is to provide additional used fuel interim storage capacity to allow continued operation of the station. The project consists of modifications to the station water pools to allow Dry Storage Containers (DSC's) to be loaded, design and construction of a UFDS Facility and upgrades to site roads to allow the DSC's to be transferred to the UFDS Facility.

The original schedule established in 2001 for initial used fuel transfers to dry storage was October 2007. This allowed for a one-year contingency in project schedule, plus a one-year buffer capacity in Darlington water pools. Both OPG and Bruce Power operate with a minimum of one-year water pool buffer capacity to accommodate unforeseen operating and production problems in water pools, the UFDS Facility and at the Dry Storage Container (DSC) manufacturing plant. The first used fuel transfers to dry storage are now expected to occur at Darlington by January 2008.

The release history/plans for this project are summarized below:

1) Work under previous Releases	
Jan 2001	- developmental release of $2.4 M approved by VP, Nuclear Waste Management Division to submit a Comprehensive Environmental Assessment (EA) Study to the Canadian Nuclear Safety Commission (CNSC). EA approval was granted in November 2003 for a Used Fuel Dry Storage (UFDS) Facility and up to 3 storage buildings (total capacity for 1,500 DCS's). This should provide used fuel storage capacity for a 40 year operating life for the four Darlington units.
Nov 2002	- developmental release of $5.4 M approved by VP, Nuclear Waste Management Division (bringing the total release to $7.8 M) for (a) preliminary engineering of a UFDS Facility and In-Station Modifications, and (b) to prepare and submit an application for a Construction License to the CNSC. Construction license was granted in August 2004.
Jun 2004	- partial release of $12.2 M approved by OPG Board of Directors (bringing the total release to $20.0 M) to complete the detailed design and specifications of the in-station modifications, together with the CNSC approval. This work has been completed.
Mar 2005	- partial release of $52.5 M approved by OPG Board of Directors (bringing the total release to $72.5 M) for detailed design and construction of the UFDS Facility, including the processing building, one storage building for 500 DSC's in a new security protected zone, and road upgrades at the Darlington site. This work has been completed.

Jun 2006	- partial release of $21.3 M approved by OPG Board of Directors (bringing the total release to $93.8 M) for installation of equipment and modifications to the Fuel Facility Auxiliary Area (FFAA) West and the acquisition of long-lead time items for the FFAA East. The FFAA West is targeted for service by Dec. 2007, 4 months ahead of schedule.
2) Work to be done under this Release	
Nov 2007	- final release of $11.9 M for installation of equipment and modifications to the Fuel Facility Auxiliary Area (FFAA) – East with a projected completion date of Dec. 2008. Total project releases will be $105.7 M.

Project cost estimates are included in Appendix C.

4. ALTERNATIVES

Dry storage is the preferred method of providing additional interim storage capacity for used nuclear fuel. The rationale for this alternative was established in earlier project releases (see notes 1 & 2). Dry storage is used at the Pickering Waste Management Facility and at the Western Waste Management Facility (located at the Bruce Nuclear Site). The same Dry Storage Container design is also being used at all these facilities.

5. THE PROPOSAL

This final phase of the overall project includes the installation of equipment and modifications to the FFAA East by December 2008. The project milestones include:

- Dec 2007 – Final contractual arrangements in place
- Apr 2008 – Concrete demolition complete
- May 2008 – Complete installation of impact pads (2)
- Dec 2008 – FFAA – East available for service (AFS)
- Oct 2009 – Project Closeout

[1] Business Case Summary (BCS), Darlington Used Fuel Dry Storage (DUFDS) Project - Release #3 - Detailed Engineering of In-Station Modifications, June 2004

[2] BCS, DUFDS Project - Release #4 - Detailed Design & Const'n. of Dry Storage Facility, March 24, 2005

6. QUALITATIVE FACTORS

The use of DSC's is consistent with the long-term management recommendations for used nuclear fuel submitted by the Nuclear Waste Management Organization to the Federal government.

The completion of the Darlington UFDS Project will allow the Darlington Nuclear Generating Station to continue to operate beyond 2009.

A Sustainable Energy Development Impact Assessment was conducted for the Western Used Fuel Dry Storage Facility in 2000. For a similar installation, the assessment concluded that the approach of using DSC's has the least impact on the environment when compared to the assessed alternatives.

7. RISKS

The current estimate is based on detailed design work conducted by an experienced Canadian nuclear engineering company, with a competitively-bid construction contract. The modifications to the west pool are anticipated to be completed by December 2007, and the lessons learned are being applied to finalize the funding/scheduling requirements for the east pool.

The risks built into the contingency funds are presented in Appendix A.

8. POST IMPLEMENTATION REVIEW (PIR) PLAN

A Comprehensive Post Implementation Review (PIR) will be carried out for the overall project ($105.7 M) within one year of the in-service dates of both Fuel Facility Auxiliary Areas (by Dec. 2009), consistent with the corporate PIR Procedure. It will be conducted by an Independent Team with the Team Leader appointed by the Project Approval Authority. The Comprehensive PIR will be an independent and systematic performance evaluation of the project for these objectives:

(a) assess the realization of the project benefits consisting of:

  (1) the detailed design and specification of the in-station modifications; and

  (2) the installation of equipment and modifications to the FFAA.

(b) review project plan, implementation and operational performance;

(c) review BCS - major assumptions, economic and financial evaluation looking back from results, for future decisions;

(d) review project risk management; and

(e) Identify over-all lessons learned, in addition to those documented by the project team, for future improvement.

APPENDIX A: Risk Summary – 2008 to 2009

Reference	Risk	Probability	Impact	Mitigation Measures	Contingency Exposure ($k)	Risk Factor	Total ($k)
1	Cost - Material costs escalate in 2008.	H	M	Advance purchase and fabrication where possible.	300	0.33	100
2	Schedule - Regular or emergent fuel handling/station work requires the project to vacate the work area. Potential schedule delays of up to 6 days per month.	M	M	Signed coordination agreement between the station and the project.	1,000	0.30	300
3	Cost - Costs higher due to design errors, plant configuration issues. Design contract extension amount higher than estimated.	H	M	Contract change process and process for field changes and installation package release. Definition of design scope of work.	600	0.40	240
4	Schedule/Cost - Closeout activities longer in duration due to contractual terms and conditions.	H	L	Project closeout process in place. Start closeout early.	250	0.40	100
5	Cost - Concrete has radioactive contamination, causing higher waste costs. Risk of "clean" disposal site shutdown increases cost.	H	M	Lessons learned from FFAA - West waste handling (>$800k cost) used to lower costs for FFAA - East. Contingency plan for waste site.	600	0.50	300
6	Resourcing - Future contractor labour shortage occurs, resulting in inability of contractor to maintain schedule and quality.	M	M	Contract award to secure resources.	250	0.50	125
				SUB-TOTAL			**1,165**
7	Unforeseen miscellaneous items (unknown unknowns)			Communication and project meetings.	725	1	725
				TOTAL			**1,890**

Note:

The risk summary applies to the balance of work required to complete the in-station modifications for FFAA – East.

For Internal Project Cost Control

APPENDIX B: PROJECT CASH FLOWS & BUSINESS PLAN

The project cash flows and approved business plan funding are provided in the table below. The additional funding required to implement the In-Station Modifications can be accommodated within OPG Nuclear's approved business plan envelope.

Table 2: In-Station Modifications (Capital)

	Year				Totals
	2001 - 6	2007	2008	2009	
Current Estimate ($M)	15.4	16.6	14.0	1.8	47.8
Current Estimate w/o Contingency ($M)	15.4	14.6	12.3	1.6	43.9
Business Plan ($M)	15.4	11.2	16.1	0.9	43.6
Variance to Business Plan (including contingency) ($M)	-	5.4	(2.1)	0.9	4.2
Variance to Business Plan (excluding contingency) ($M)	-	3.4	(3.8)	0.7	0.3

Table 3: Dry Storage Facility (Nuclear Waste Provisions)

	Year				Totals
	2001 - 6	2007	2008	2009	
Current Estimate ($M)	35.3	20.5	0.5	-	56.3
Business Plan ($M)	35.3	25.2	0	-	60.5
Variance ($M)	-	(4.7)	0.5	-	(4.2)

APPENDIX C: PROJECT COST ESTIMATES

Darlington Used Fuel Dry Storage Project - Cost Estimates ($k)

($k)		Y/E 2006	2007	2008	2009	Totals
1	Design-Owners Agent	2,350	380	830	470	4,030
2	Design Agency	4,190	760	950	380	6,280
3	Other contracts	2,940	80	50	0	3,070
4	OPG Project Management	1,230	960	950	250	3,390
5	OPG CMO / FE / Support	2,030	1,230	1,190	240	4,690
6	Construction Labour and Fabrication	1,300	6,590	4,700	0	12,590
7	Waste Handling	0	0	910	0	910
8	Long Lead (LL) Materials	0	1,550	1,040	0	2,590
9	Advance EFFAA LL Materials	0	540	0	0	540
10	Advance EFFAA construction	0	670	0	0	670
11	General Material	0	430	240	0	670
12	Travel and Board	0	70	70	0	140
13	Letter of Credit	0	40	0	0	40
14	Specific Contingency	0	80	290	80	450
15	Interest	1,360	1,230	1,080	160	3,830
	Subtotal	15,400	14,610	12,300	1,580	43,890
16	Contingency	0	2,010	1,680	210	3,900
	In-Station Totals	15,400	16,620	13,980	1,790	47,790

Dry Storage Facility	32,668	25,232	0	0	57,900
Project Totals	48,068	41,852	13,980	1,790	105,690

Approved by: Greg Gordon, Acting Section Manager
Design Projects, Darlington

4-DEC 2007
Date

Auxiliary Heating System Project 16 - 34000

Developmental Release Business Case Summary D-BCS-73110-10001-R000

1/ RECOMMENDATION:

We recommend a release of $2.2M (including [redacted] contingency) of developmental funding to complete the 'Definition Phase' of the Auxiliary Heating System (AHS) Project with the intention of placing a new system in service by the Fall of 2008.

The business objective of this project is to provide a reliable back-up supply of heating steam to prevent major equipment damage and thereby support the safe return of Darlington units to service following a four unit shutdown during the winter months. This will be achieved by replacing the existing Construction Boilerhouse with a facility that can, in the event of a four unit shutdown, maintain the temperature inside the Powerhouse and TRF/HWMB above 10°C to prevent impairment of both safety and non-safety related systems due to heavy water freezing (heavy water freezes at +4.8°C).

The existing Construction Boilerhouse (CBH) cannot continue to provide this capability because:

- it does not have sufficient installed capacity
- the building and oil feeder piping are not fully compliant
- it was never designed as a permanent system and is costly to maintain.
- it does not meet reliability requirements from both a nuclear safety and conventional risk assessment

Refurbishment of the CBH is not recommended because:

- it would cost at least as much as replacement with greater cost and schedule risks.
- it would result in the unavailability of a back-up system for up to two heating seasons.

...is project is consistent with the approved 2006-2010 Business Plan with $2M budgeted for 2006.

A Project Execution Plan (PEP) will be prepared as a deliverable of this release and submitted for approval by 30 Nov 06.

$000's Capital		Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Developmental	0	[redacted]	Feb.06	Spent Life to Date:	0
Requested Now:	Developmental	2,200	[redacted]	2006-2010	Appr'd Business Plan (Tot Proj):	[redacted]
Cumulative Release:	Total to Date	2,200	[redacted]	2006-2010	Business Plan Variance:	[redacted]
Total Project Estimate:	+60% to -25%	23,505	[redacted]	2006	Budget (Current Year)	[redacted]
Current Year Estimate:	2006	2,200	[redacted]	2006	Budget Variance (Current Yr)	[redacted]
Type of Investment:	Sustaining	N/A	[redacted]	Cumulative Release Remaining:		[redacted]
NPV:		N/A	[redacted]	Contingency on Remaining Release:		[redacted]
IRR:		N/A	[redacted]	Contingency % on Remaining Release:		[redacted]

Submitted By:

21 Mar 2006

M. Amone
Director, Projects & Modifications
Date:

Finance Approval:

20 Mar 06

G. Brown
Controller, Engineering & Modifications
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

23 Mar 2006

Stu Seedhouse
Director, Station Engineering, Darlington
Date:

2/ BACKGROUND & ISSUES

Purpose of the AHS

Extraction steam from any one single operating unit provides adequate heating steam to meet the needs of the station. However, when all four units are shutdown and there is a possibility of heavy water freezing, an alternate supply provided by the AHS is required to maintain general heating and the availability of Group I safety systems. Group II systems are protected with electric heaters fed from the Emergency Power System and are therefore not impacted.

Planned station outages requiring the use of the AHS typically occur every 6 years with the next in 2009, however, there is a real and ongoing risk of a forced shutdown should any of the following events occur:

- A Design Basis Accident (DBA).
- A common safety system fails.
- Darlington is found to be operating outside of the boundaries of the Safe Operating Envelope (SOE) and is un-repairable.
- The design of Darlington is found to be inadequate to meet the safety basis of the plant.
- A generic problem is found on a significant production component.
- A labour disruption, regulatory order or other external disruptions.

A system with an unavailability of approximately $1x10^{-2}$ has been deemed necessary to mitigate the risks of such an unplanned event.

Regulatory Issues

In 1987, the AECB questioned Darlington's crediting of reactor decay heat and heat transport thermal energy to provide sufficient building heating until such time as portable heaters could be distributed throughout the station. The ability of portable heaters to heat such a large area was also further questioned. In response, Darlington committed to maintaining a sufficient number of construction boilers until a permanent solution was put in place. Reference Action Item AI#851312.

During the 1997 vacuum building outage, a capacity test of the CBH was performed which demonstrated the ability of the facility to provide adequate heating. AI #851312 was subsequently closed out.

Due to ongoing legacy issues with the CBH, routine project status reports are provided to the CNSC to demonstrate Darlington's commitment to a long term action plan to ensure a reliable supply of auxiliary heating. The latest of these are NK38-CORR-00531-12553, NK38-CORR-00531-12666 and NK38-CORR-00531-12915 associated with REG M Action Items #28060617 and #28060618. The next required update is at the end of Q1 2006.

CNSC correspondences, NK38-CORR-00531-12240 and NK38-CORR-00531-12358, document CBH compliance issues (see SCR D-2004-00415 & D-2004-01239) and Darlington's commitment to resolving the issue of the Backup Heating Fuel System by December 2007.

Existing Conditions

The current CBH facility, consisting of four electric boilers and eight oil-fired boilers, is approaching its end of life. It was placed into service at the time of site construction (some 27 years ago). Even at that time, the oil-fired boilers were previously used (average age is now >40 years) and were obtained from other construction sites. Several of these boilers require major repairs and/or re-tubing. The electric boilers which supply the majority of the load are also aged and will require major refurbishment in the coming years.

For the short term, compensatory actions are implemented every fall to survive the impending winter. This is very expensive (in excess of $0.5M base OM&A costs per year in corrective maintenance alone and in 2003/ 2004, an additional $1.2M for a rental boiler) and imposes unacceptable risk to the station.
It is projected that at least $0.5 M per year in corrective maintenance will continue until the CBH is replaced.

In 2004, SCR D-2004-08451 was initiated due to concerns about the structural adequacy of the CBH. The assessment of the building concluded that the building structure had degraded and will not support all loads required by the Building Code. Until a new facility is constructed, work request (WR# 449004) has been initiated to have the CBH structure strengthened.

It has also recently been determined that it is not possible to establish a realistic unavailability for the CBH since the equipment is old and the design documentation is minimal and in some cases non-existent. It is also very time consuming with minimal potential for returns.

Refurbishment of CBH

A detailed conceptual study examining possible alternatives, including refurbishment of the existing CBH, was performed in 2000. At that time, limitations of the existing facility were recognized and the preferred alternative was a system which predominately relied on the bulk electrical system, i.e. electric heaters/boilers, due to its perceived reliability. However, as a result of the LOBES event of 2003, a new study was undertaken in 2004 to examine alternatives which did not rely on the bulk electrical system. Two main options were identified; co-generation and oil fired. Due to the much higher cost and timeline and the need for an environmental assessment, co-generation was ruled out. Although black start capability is currently not a design requirement of the AHS, it can be economically retrofit into an oil fired system if the need should arise.

A draft report recently prepared by Darlington Projects Design also concluded that refurbishment of the existing facility while technically feasible was not recommended due to the high cost and risks involved. (Ref. draft Engineering Report NK38-REP-73110-10001)

Links to Other Projects

Both Darlington and Pickering have similar requirements to provide auxiliary heating steam. However, due to different plant configurations, the final solution is expected to be tailored to suit the specific station configuration. Pickering requires a minimum capacity of 21,000 Kg/hr of heating steam, whereas Darlington requires approximately double that capacity.

The Design Units from both Darlington and Pickering are in consultation with each other to maintain a consistent approach and design basis.

There are no direct links to other projects. However, maintaining turbine hall roof dampers of the Powerhouse Steam Venting System (PSVS) open, as is the current practice will necessitate an increase of approximately 10% of AHS capacity.
Project #34002 is currently addressing deficiencies with PSVS including the need to maintain these dampers open.
Although, the decision to close these dampers when the AHS is required is a possibility, it is not currently practical. These dampers are not maintained and tested (air supply is disconnected in the field) and may not close when required. In addition, it will take a team of operators (a commodity that is not available when the station is in an emergency four unit shutdown and the weather is freezing outside) and control maintenance personnel (who may be in a similar position) to make this happen.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Do Nothing (Not Recommended)

This is not recommended as:

- the risk of severe equipment damage exists should the AHS be required under very harsh conditions due to the limited capacity and unknown reliability.
- Regulatory issues will not be addressed as the building and oil feeder piping are not fully compliant.
- the CBH was never designed as a permanent system and is costly to maintain.

Alternative 1 – Install new Auxiliary Heating System (Recommended)

We recommend installing a completely new Auxiliary Heating System Facility located adjacent to the existing Construction Boiler House, outside of the protected area.
The new facility will be primarily oil-fired and will utilize existing services and infrastructure to the extent possible. 'Black start' capability, if required in the approved design requirement, will be provided, otherwise, the design will be conducive to a retrofit should the need arise in the future.

This is the recommended alternative as it is the lowest cost option that satisfies the business objective. It provides for 'black start' capabilities and is expandable to accommodate future needs (i.e. station de-commissioning and/ or new construction).

This Developmental Release BCS will be utilized to complete the Preliminary Engineering (Project Definition Phase) and the Full Release BCS. The PEP will also be prepared as a deliverable of this release.

Alternative 2 - Delay the Recommendation (Not Recommended)

This is not recommended as the station will continue to:

- be at risk of severe equipment damage should the AHS be required under very harsh conditions.
- not address regulatory issues associated with the building and piping system for which we have committed to resolve by December 2007.
- perform costly annual maintenance of CBH as it was never designed as a permanent system.

Alternative 3 - Do Less (Not Recommended)

The 'Do Less' alternative involves partial refurbishment of the existing facility which is costly and will not meet the business objectives of the project.

Alternative 4 - Do More (Not Recommended)

This is not recommended as there is no way to include additional features without adding cost. The recommended alternative satisfies the business objectives

Alternative 5 – Other - Co-generation Plant (Not Recommended)

A Co-Generation plant, estimated at $100M is not recommended as the break even rate is estimated to be not achievable. There also does not appear to be any corporate drivers to merit this alternative at this time.
In addition, it is unlikely that real estate will be available at Darlington to site the cogeneration plant in such a way that the steam transmission lines can be kept reasonably short. Also, delays due to the likely need for an environmental assessment will make meeting the project schedule impossible.

Alternative 6 – Other – Electric boilers in Unit 4 (Not Recommended)

We do not recommend the installation of electric boilers in the Unit 4 Powerhouse Extension Bay, with power supplied from the Bulk Electric System (BES) as the space available in the Unit 4 Powerhouse Extension Bay is not adequate. In addition, this alternative does not cater to a black start capability should that be deemed as necessary.

Alternative 7 – Other – Relocate the REPG from PND to DND (Not Recommended)

We do not recommend using the Pickering REPG (22.5 MW) turbine generator as:

- this system is undersized.
- it still requires a boiler facility and associated costs to produce steam.
- it is an inefficient method of producing steam (using jet-engine fuel to produce electricity, to produce heat to produce steam).
- it is very complex and costly to operate and maintain.

As this system is owned by OPG and is available in 2007, it will be explored further as part of this release and considered a potential alternative until proven otherwise.

Alternative 8 – Other – Use of Gas Fired Boilers (Not Recommended)

We do not recommend the use of a gas fired boiler facility since natural gas is currently not available on site and would be very costly to supply. Since the facility operates very infrequently, the higher cost of fuel oil is far outweighed by the capital cost of supplying natural gas. The use of natural gas would also introduce a hazard to the site which currently does not exist.

4/ THE PROPOSAL

This Developmental Release BCS will be used to:

- validate the recommended alternative.
- complete the necessary design and procurement documentation to secure an external design contractor i.e. Design Plan, Design Requirements, Technical Specifications, Design Agency Interface Agreements, Request for Proposals
- complete all required assessments and sufficient detailed design to support preparation of a Full Release BCS
- fund the use of a third party estimator (Helyar).
- complete all necessary project management documentation required for this phase of the project including the Project Execution Plan
- Prepare a Full Release BCS.

Milestones below are for this Developmental Release BCS only.

Milestones Finish Date (D/M/Y)	Description
31-Mar-06	Developmental Release BCS approved
30-May-06	Issue the RFP for an external design agency
30-Jul-06	Award design agency contract (PO)
30-Nov-06	PEP approved
28-Feb-07	Full Release BCS approved

5/ QUALITATIVE FACTORS

N/A

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Project requires additional funding	The funding requested may not be adequate to complete necessary design activities.	Medium	Competitive bid process will be used to secure the design contractor. PO will be awarded as a 'Fixed Price' contract. A general contingency of [redacted] is available.	Low
Scope				
Increase in project scope.	Higher cost/ longer schedule	Medium	Original project scope was larger than is now being proposed. The current scope as defined in the preliminary design requirements has been fine tuned and agreed to by all stakeholders as the minimum required to meet station and regulatory requirements. A formal scope change control process will be used to control scope.	Low
Schedule				
Piping (oil-feeder from SG tanks) will not be code compliant by Dec. 2007	CNSC commitment will not be met. Darlington will not be allowed to use fuel oil piping from the SG tanks to the existing boilerhouse.	High	Seek a deferral that can be achieved on the present schedule and/ or ensure that the piping is completed first.	Low
Resources				
Lack of Project Designers.	Project deliverables delayed, with a delay in the project schedule.	High	Design activities will be contracted out to the extent possible to a known design agency to minimize the involvement of station resources.	Medium

Technical				
Commercially available boiler systems are very mature and widely used in other industries. Technical risk is considered low.		**N/A**		
Regulatory				
See Schedule Risk.		**High**		**Low**
Environmental				
New Certificate of Authorization may be required for new facility.	Not granted due to increased emissions.	**Medium**	Environmental Group has been consulted. Initial assessment is that a new C of A will not be required. If conditions support this assessment change, an application will be submitted as early as possible in the design phase.	**Low**
Health & Safety				
N/A				
Investment				
System may not meet requirements	Solution is known and technology is very mature.	**Low**	No mitigation required.	**N/A**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
N/A	Choose Month Choose Year	Choose Month Choose Year	N/A

Comments:
This is a Developmental Release BCS only. PIR will be developed for Full Release.

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Auxiliary Heating System Project 16 - 34000

Developmental Release Business Case Summary D-BCS-73110-10001-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Years 2005	2006	2007	2008			Total	LTD This Mth	LTD %
Project Management (OPG)		270	397	517			1,184	-	0.0%
Engineering & Drafting (OPG)		360	289	323			972	-	0.0%
Material	[redacted]								
Installation – PWU, BTU									
Contract – Project Mgmt									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Sub Total (excl Contingency)									
General Contingency									
Specific Contingency									
Grand Total		2,200	10,350	10,955			23,505	N/A	N/A
2006-2010 Business Plan		2,000	9,000	9,525			20,525	N/A	N/A
Variance to Business Plan (excl Contingency)			-	-			-	N/A	N/A

Removal Costs included in above	0
Definition Costs included in above	0
Estimate Name, Quality, etc	Conceptual Estimate +60% to -25%
Design Complete:	Zero to Minimal

Reviewed By:

23FEB2006
Date:

[S]ahil Rahman
[Pr]oject Manager P 24/2/2006

Approved By:

27 FEB 06
Date:

Robert Black
Manager (Strat IV), Design Projects

DNGS FEEDER REPLACEMENT ALARA 16 - 34008

Superseding Business Case D - BCS - 33160 - 10005 – R002

1/ RECOMMENDATION:

Approval is requested for an additional 2,292 K$ in 2009 capital funding to complete this project, for a total cost of 13,992 K$.

The funding for this project will provide tooling and capability to optimize feeder replacements, fuel channel reconfiguration and single fuel channel replacements. Optimization of these activities will substantially reduce dose uptake and outage duration.

The additional funding is required:

- To complete work that is in progress, namely commissioning of the trolley mounted magazine and upgrading of the fuel handling software; both are more complex than anticipated, requiring design changes and thus resulting in higher costs.
- Due to cost increases associated with modifications to the channel isolation plugs and vented closure plugs.
- Field support labour costs for platform wing extension installation and commissioning were not considered in the original estimate.
- Due to schedule delays, which have resulted in higher labour costs.
- Due to higher interest costs, which have been mitigated by declaring approximately 70% of the project total in service.

Increased costs are mitigated somewhat by a reduction in the Contingency.

There are many advantages to completing the additional scope of this project, such as the fact that it will net an additional two days of critical path for a typical planned outage with up to 16 feeders to replace. Another day is also saved for each block of 16 additional feeders.

$000's (incl contingency)	Type	LTD 2008	2009	2010	2011	2012	2013	Later	Total
Currently Released	Full	11,544	156						11,700
Requested Now	Superseding	(118)	2,410						2,292
Future Funding Req'd	N/A								-
Total Project Costs		11,426	2,566	-	-	-	-	-	13,992
Non Project Costs									-
Grand Total		11,426	2,566	-	-	-	-	-	13,992
Investment Type Value Enhancing		Class Capital		NPV 17.2 M$		IRR 85.2%		Discounted Payback n/a	

Submitted By:

S. Seedhouse
Senior VP Darlington

Date: 13 Aug 2009

Finance Approval:

R. Leavitt
VP, Nuclear Finance

Date: Aug 17, 2009.

Line Approval (Per 1.1):

W. Robbins
Chief Nuclear Officer

Date: Aug 18/09

2/ BACKGROUND & ISSUES

The feeders in the Darlington reactors interface with the reactor primary heat transport (PHT) inlet and outlet headers and the reactor fuel channels, and thus are critical to the reactor operation. The requirement for feeder replacements at Darlington is associated with the high rates of wall thinning due to flow accelerated corrosion (FAC). Wall thinning rates are determined following periodic inspections that are performed under the PHT Feeder Piping Aging Management Strategy and Plan and the CSA N285.4 Standard.

Feeder replacement preparation and execution were performed under OM&A project 38460 in 2006 and under Outage OM&A 30461 from 2007 onwards. This project is intended to provide the required capability to perform feeder replacements efficiently and effectively. The current Business Plan and Generation Plan shows a total of approximately 48 feeder replacements required in Darlington Units during the 2009 to 2013 window.

Following the Unit 1 outage in 2008 the fuel channel inspection strategy changed from terminal solid solubility (TSS) inspections to body of tube scrape campaigns. Similarly to feeder replacements, fuel channel scrape inspections are performed by personnel on the reactor face, therefore fuel channel inspections are an additional benefit to this project.

Issues considered when developing the requirements of this project are as follows:

1. Feeder replacement and fuel channel inspection are critical path activities during outages. Any opportunity to minimize their execution windows is an economic benefit to the corporation and provides greater fleet outage flexibility.
2. Darlington does not have capability to perform feeder replacements in parallel and our current fuel channel isolation tools have limitations. These tools do not allow parallel fuel channel isolations.
3. Feeder replacement and fuel channel scrape inspection are dose intensive operations. There is a need to minimize dose uptake as per the ALARA principles.
4. Critical path analysis to identify outage windows in the Generation Plan were based on certain assumptions or optimization strategies. They are:
   a) Capability to do feeder replacements in parallel on both reactor faces by 2008, if there are > 8 replacements.
   b) Greater flexibility in channel isolation. For this, a new and improved channel drain tool package was purchased; the vented closure plug.
   c) Develop capability to isolate more than 8 fuel channels on each reactor face, without having to bring the fueling machine back to the reactor face.
   d) Fuel handling software upgrades to track installation of channel isolation plugs in more than 5 fuel channels. Tracking provides precise control of CIP location and eliminates the risk of leaving a CIP in channel and preventing cooling of a fuelled channel.

The recommended work under this project will provide Darlington the following capabilities:

- Isolation of more than 8 fuel channels (FC) on each reactor face, without having to bring the fuelling machine (FM) back to the reactor face.
- Optimization of feeder replacement and fuel channel scrape durations and reduce dose associated with these activities.
- Provision of maintenance platform wing extensions has mitigated the requirement to erect and disassemble scaffolding in the reactor vault, for each bridge movement, associated with accessing peripheral feeders for replacement. Of the 8 feeder replacements executed at Darlington 4 have been peripheral feeders.

- Availability of channel isolation plugs (CIP) for feeder replacement campaigns has mitigated dose associated with ice plugging. There is only one ice plug required instead of two, therefore the dose associated with ice plugging has been reduced by 50%.
- A trolley mounted storage magazine will mitigate the need to manhandle shield plugs for campaigns greater than 8 feeders per reactor face when CIP's are used. The channel isolation plugs replace the shield plugs in the end fitting supporting ice plug formation. Shield plugs have dose rates as high as 20 to 30 REM/hr contact. The TMM will also support delivery and installation of the vented closure plugs (VCP).
- Reduced radiation fields associated with mini platform shielding improvements are expected to result in a reduction of approximately 2 REM per inspection campaign when these canopies are used.
- Facilitate the closure plug replacement program; replacement is required to eliminate closure plug leakage.
- Future opportunities/potential to facilitate other operations, maintenance and refurbishment programs.

Summary of work completed under the existing funding release is as follows:

- Qualification of the mini platform and partial maintenance platform to be used as an elevating working platform (EWP).
- Modification of the maintenance platform by adding wing extensions to access reactor face areas that were previously not attainable.
- Commissioning of 7 outlet CIPs that were designed and developed under the Feeder Integrity Project (FIP), including available for service (AFS) completion.
- Modification of CIP design to correct design deficiency and permit reduced channel draining time.
- Design of the VCP (modified Channel Drain Tool) to allow fuel channel isolation with the reactor bridge at variable locations and quicker channel drain times. Commissioning and AFS is complete.
- Procurement of 14 VCPs (not identified in initial BCS).
- Modification of the Mini Platform Shielding Canopy Roof, which will minimize radiation shine from the feeder cabinet.
- Fueling machine trolley mounted magazine (TMM) developed and provided to store CIP's, shield plugs, closure plugs and vented closure plugs to improve the fuel channel isolation process.
- Procurement of 10 additional CIPs to support large feeder replacement and body of tube fuel channel scrape campaigns.

Summary of the work that has been de-scoped from the project scope due to changing needs and financial constraints is as follows:

- Design and fabricate new freezing jackets.
- Modification of the maintenance platform shielding canopy. It was determined that this was not beneficial because other forms of shielding are used for feeder replacements. Also, a canopy would not be beneficial for fuel channel reconfiguration, since reconfiguration is complete after D931.
- The procurement of 15 additional CIP's was reduced to 10.
- Storage capability of TMM was decreased from 20 channels to 12.

The additional funding requested in this BCS is required:

- To complete work that is in progress, namely commissioning of the trolley mounted magazine and upgrading of the fuel handling software; both are more complex than anticipated, requiring design changes and thus resulting in higher costs.
- Due to cost increases associated with modifications to the channel isolation plugs (modifications to the rear of the plug to reduce the time to drain a channel) and vented closure plugs.
- Field support labour costs for platform wing extension installation and commissioning were not considered in the original estimate.
- Due to schedule delays, which have resulted in higher labour costs.
- Due to higher interest costs, which have been mitigated by declaring approximately 70% of the project total in service.

Increased costs are mitigated somewhat by a reduction in the Contingency.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2	Alt 3	Alt 4	Alt 5
Revenue		175,021	37,953				
OM&A							
Capital		(13,992)	(2,292)				
Present Value (PV)		75,600	17,237				
Net Present Value (NPV)	**N/A**	**75,600**	**17,237**				
Internal Rate of Return (IRR) %	N/A	85.2%	n/a				
Discounted Payback (Yrs)	N/A	n/a	n/a				

Base Case: Not Recommended - Do not complete project.
This is not the recommended alternative.
Without additional funding, the TMM and FH Upgraded Software will not be available for use. Without the TMM, DNGS is limited to isolating 8 channels at a time and the time to isolate a channel is increased by 6 hours/channel. As well, the TMM is built and delivered, however it can not be used until it and the FH software commissioning is complete.

Alt. 1: Recommended - Complete project with additional scope.
This is the preferred alternative.
With almost 85% of the project spent, the project benefits could not be realized without completing the project. The additional funding required has been mitigated significantly by a sizeable reduction in Contingency.

Alt. 2: Not Recommended - Delay completion.
This is not the recommended alternative.
Delay is not recommended as the lack of TMM will have a significant impact on D931. For D931 13 of the 15 channels being drained will be on one face, therefore without the TMM available for installation of isolation and draining equipment the D931 outage duration would be extended by approximately 4 days.

Alt. 3: N/A

Alt 4: N/A

Alt. 5: N/A

4/ THE PROPOSAL

The recommended work includes completing all analysis, documentation, tooling design, fabrication and commissioning, modifications to existing tooling, and training for safe execution.
The project deliverables for the entire project are as follows:

1. **Platform qualification as an Elevating Working Platform.**
This is required for both feeder replacements and fuel channel reconfiguration. Work needs to be done to meet Ontario Health and Safety Act (OHSA) requirements (both legal and safety) and implement restrictions via procedures to use the current maintenance platform and reactor bridge as an elevating working platform (EWP). This is required for the Fall 2006 outage (D611). This task is complete.

2. **SFCR Platform Wing Extensions.**
Design, build, fabricate and commission wing extensions for East and West Maintenance platforms to access feeder areas, not reachable from the existing maintenance platform. This will eliminate the need to build scaffolds on critical path and save dose and critical path time. Required for feeder replacements in the Fall 2006 outage (D611). This task is complete.

3. **Channel Isolation Plug (CIP) Commissioning and AFS.**
Commission existing 7 CIP's and implement required updates to Fuel Handling Operating Sequence Code (Op Data) to allow installation and removal of CIP's using fuelling machine (FM). The CIP function is to allow a fuel channel to be isolated for feeder replacement with a single ice plug, rather than using two ice plugs which is the current requirement for channel isolation. The CIP was designed by GE and delivered in 2003 by IMS under the Feeder Integrity Project. It was not commissioned. These are required for feeder replacements in the Fall 2006 outage (D611) and going forward. This task is complete.

4. **Vented Closure Plug (Modified Channel Drain Tool).**
Re-design Channel Drain Tool (CDT) package to provide greater flexibility in fuel channel isolation. The Vented Closure Plug was available for use in the Spring 2008 outage D811, this task is complete.

5. **Mini-Platform Shielding Canopy Modification.**
This is required to extend the canopy roof to minimize radiation dose uptake from the feeder cabinet. This canopy is used to execute feeder inspections. Canopy modification is complete and available for use in VBO/D931.

6. **Procure additional 10 CIP's**.
To allow fuel channel isolations for the larger feeder replacement campaign and modify existing inlet CIP's and rear bodies to correct existing design deficiencies. Inlet modification is complete and CIPs are expected to be delivered with modified rear bodies by December 2008 and to be available for use in January 2009. Costs are committed.

7. **FM Trolley Mounted Storage Magazine.**
Design and fabricate a fuelling machine (FM) trolley mounted storage magazine to store CIP's, shield plug, and closure plugs to improve the fuel channel isolation process. Install a Fuelling Machine Trolley Control System modification to integrate Storage Magazine Controls. The magazine will allow storage of up to 12 items such as shield plugs, closure plugs, CIPs or modified closure plugs or any combination of those. Storage of these components eliminates the need to manhandle high dose shield plugs for numbers greater than 8 per face or the need to remove and re-install platforms to manage the 8 shield plug limitation. Stage 1 commissioning is planned for November 2008 and stage 3 commissioning will be completed during D931.

8. **Upgrade the Fuel Handling Software**.
To provide capability to track Channel Isolation Plugs in the reactor and to interface with the Storage Magazine Control System. Stage 2 commissioning was completed in March 2009, therefore upgraded software is available for D931 for Trolley 5/6. Trolley 1/2 and 3/4 commissioning will take place at a later date.

5/ QUALITATIVE FACTORS

1. This preparatory work is required in support of the Feeder Replacement and Fuel Channel Inspection Program to allow us to deal with the results of the inspections performed under the PHT Feeder Piping Aging Management Strategy and Plan and the CSA N285.4 Standard.
2. Feeder Replacement Program is required to operate the component safely and keep them in a safe condition as required by the Nuclear Power Reactor Operating License (NPROL) license condition 5.2. Tools and capability developed by this project will improve the efficiency of the feeder replacement program.
3. Availability of the TMM will facilitate the closure plug replacement program.
4. Future opportunity/potential to facilitate other operations, maintenance and refurbishment programs.

6/ RISKS (see Attachment D for details)

		Low = 1 to 3	Medium = 4 to 9	High = 10 to 25		
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Funding may not be sufficient.	15% contingency added.	6									2								

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	July 2009	Dec 2009	Reactor Maintenance Engineering

Comments:

A simplified Post Implementation Review will be done for the project as part of the project closeout. The PIR will evaluate the completion of steps which would lead to success:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Mini Platform and Partial SFCR Platform qualification as an Elevating Working Platform (EWP) completed	May not be qualified as an EWP.	To be qualified as an EWP.	Standard procedural compliance. OSHA and legal requirement compliance. Report issued.	IMS Engineering/Reactor Maintenance Engineering
2.	SFCR Platform Wing Extensions completed	No access to peripheral feeders.	Provide approved extensions to the existing platform.	Ability to work on peripheral feeders, normally accessible only by scaffolding.	IMS Engineering/ Reactor Maintenance Engineering
3.	CIP commissioning and AFS completed	Feeder isolation capability limited to approx two feeder replacements at one time.	Double feeder isolation capability	AFS completed	Fuel Handling/IMS Engineering
4.	Mini-platform Shielding Canopy modification completed	Existing shielding canopy provides limited dose reduction for feeder inspection and other reactor face work.	Extension of the shielding canopy provides better protection against radiation dose uptake.	Availability for reactor face work.	Reactor Maintenance Engineering
5.	Re-design of CDT package completed (Vented Closure Plug)	Pressure relief capability not provided internally	VCP installed in channel for ice plug formation rather than FM or CDT protruding from face on fuel channel.	AFS completed D811.	Fuel Handling/Reactor Maintenance Engineering
6.	Storage Magazine to be installed on FM Trolley	No flexibility in channel isolation. Need multiple visits to Fuel Bay.	To store up to 12 Shield Plugs, CIPs, and Closure Plug.	Free-up fuelling machine for fuelling during feeder replacement window	Fuel Handling/Reactor Maintenance Engineering

7.	Fuel Handling (FH) Software upgrade to track CIP locations in the reactor	FH Operating Manual and Software cannot support use of multiple CIPs or the Storage Magazine on the FM trolley.	OM updated and Software upgraded.	Allow multiple CIP use and interface with the system control for the Storage Magazine on the FM trolley.	Fuel Handling/Reactor Maintenance Engineering
8.	Provision of additional Channel Isolation Plugs	Insufficient numbers exist to support a 16 feeder campaign.	Allow fuel channel isolation for the larger feeder replacement campaigns.	Provide 10 additional isolation plugs	Reactor Maintenance Engineering

Appendix "A" Glossary (acronyms, codes, technical terms)

FC – fuel channel
CIP – channel isolation plug
VCP – vented closure plug
TMM – trolley mounted magazine
EWP – elevated working platform
FIP – feeder integrity project
PHT – primary heat transport
FAC – flow accelerated corrosion

Appendix "B" Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2006	2007	2008	2009	2010	2011	2012	Later	Total
Full	Dec	2006	1,430	6,500	3,614	156					11,700
Superseding	Apr	2009	887	6,460	4,079	2,566					13,992
											0
											0
											0
											0
											0
											0

LTD Spent	Mar	2009				11,753					11,753

Comments:

Appendix "C"

Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	None	SR & D Opportunity	
Progress Payments	n/a	Foreign Currency	No	Retainer Fee	
Income Tax Rate	Generation	PST		Interest Rate (Capital)	
Depreciation Rate (Capital)	Generating Equipment 8%	Leasing		Indexed Priced Contract	

Comments:
Benefit conservatively excludes saving from executing 81 feeders on Unit 1 in 2017 as realistically such a campaign may not be considered. Including the D1711 saving increases the total benefit to 107.5 M$ and the incremental benefit to 25.7 M$.

Project Cost Estimate:

Design Complete	100%	Quality of Estimate	Release + 15% to - 10%	3rd Party Estimate	yes
Reviewed by Sponsor	yes	OPEX used	yes	Lessons Learned	yes
Similar Projects	no	Budgetary Quote(s)	yes	First Unit Actual Used	Unit 3 (D931)
Cost Sharing	no	Contracts in place	yes	Competitive Bid	no
Fixed Price Contract	no	Fee for Service	yes	Firm Vendor Proposal	yes

Comments:

Rationale for Cost Classification:

Provision of new tooling and new capabilities.

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)						
Pickering A	1											
	4											
Pickering B	5											
	6											
	7											
	8											
Darlington	1	Jun	2018	935	88%	D1111	D1411	D1711				
	2	Sep	2016			D1021	D1321	D1621				
	3	Mar	2020			D931	D1231	D1531	D1831			
	4	Dec	2021			D1041	D1341	D1641	D1931			

Comments: Benefits will continue after refurbishment, as the fuel channel scrape inspection program will continue.

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Impact on Revenue

$000's	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate KWH										
Probability										0.0%
Consequence										0
Risk										0
Other										0
Base Case	0	0	0	0	0	0	0	0	0	0
Probability										0.0%
Consequence										0
Risk										0
Other										0
Recommendation	0	0	0	0	0	0	0	0	0	0
Net Impact	0	0	0	0	0	0	0	0	0	0

Comments:

This section intentionally left blank.

Impact on OM&A

$000's	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A										0
Outage OM&A										0
Project OM&A										0
Base Case	0	0	0	0	0	0	0	0	0	0
Base OM&A										0
Outage OM&A										0
Project OM&A										0
Recommendation	0	0	0	0	0	0	0	0	0	0
Net Impact	0	0	0	0	0	0	0	0	0	0

Comments:

N/A

DNGS FEEDER REPLACEMENT - ALARA 16 - 34008
Superseding Business Case D - BCS - 33160 - 10005 – R002

Attachment "A" **Project Cost Summary**

	$000's Capital	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnt & Support	564	226							790
	Engineering	1,987	200							2,187
	Procurement	551	910							1,461
	Construction	7,698	525							8,223
	Other	5	-							5
										-
										-
										-
										-
	Interest (Capital Project Only)	621	370							991
	Project Costs	**11,426**	**2,231**	-	-	-	-	-	-	**13,657**
	General Contingency		335							335
	Specific Contingency									-
	Project Costs	**11,426**	**2,566**	-	-	-	-	-	-	**13,992**
Cash	**Adjust to Cash Basis + / -**								-	-
	Project Costs	**11,426**	**2,566**	-	-	-	-	-	-	**13,992**
Funding	**Currently Released**	11,544	156							11,700
	This Release	(118)	2,410							2,292
	Future Release	0	0						0	0
	Project Funding	**11,426**	**2,566**	-	-	-	-	-	-	**13,992**
Budget	**2009-2013 Business Plan**	3,434	1,532							4966
	Variance to Business Plan	**7,992**	**699**	-	-	-	-	-	-	**8,691**
Other	Removal Costs included above									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

The estimated variance(s) to the **2009-2013 Business Plan** will be addressed through the portfolio management process.
A PCRAF will be submitted for the money not spent in 2008 to add to 2009 funding.

Reviewed By: DBMcK 05/06/09.
D. McKenzie
Project Manager Glenn Round GRR Date: June 08/09

Approved By: S Woods 22 JUN 2009
S. Woods
Director, Station Engineering Date:

DNGS FEEDER RELACEMENT - ALARA 16 - 34008

Superseding Business Case D - BCS - 33160 – 10005 – R002

Attachment "B" **Project Variance Analysis**

	Capital	LTD Dec	Total Project Last BCS Dec 2006	Total Project This BCS Jan 2009	Variance	Comments
Scores Basis	Project Mgmnt & Support		410	790	380	Higher labour costs (trades and field support) for TMM commissioning, due to schedule delays
	Engineering		300	2187	1887	FH software upgrades complexity resulted in higher cost than original PO (Purchased Service)
	Procurement			551	551	Field support labour costs for platform wing extension installation and commissioning were not considered in originally estimate. Costs for design of feeder freezing jackets was high (which due to higher costs than originally projected was de-scoped from project and not completed)
	Construction		8010	9133	1123	Trolley Mounted Magazine complexity has resulted in change in design and higher costs. Increased costs for modification to the rear body of the Channel Isolation Plug to reduce the time to drain a channel.
	Other			5	5	Vendor travel costs
					0	
					0	
					0	
					0	
	Interest (Capital Project Only)		280	991	711	Delays in declaring equipment Available For Service have resulted in higher than anticipated interest
	Project Costs (Scores Basis)	**0**	**9000**	**13657**	**4657**	
	General Contingency		**2700**	**335**	-2365	
	Specific Contingency				0	
	Project Costs (Scores Basis)	**0**	**11700**	**13992**	**2292**	

Other	Removal Costs included above				0	
	Inventory to be written off				0	
	Spare Parts in Inventory				0	

Comments:

Attachment "C" — Milestones and In Service Declarations

Key Milestones

Completion Date			Description
Day	Mth	Yr	
30	Jun	09	TMM Stage 3 Commissioning and Final AFS Complete
30	Sept	09	Installation of pads and electrical wiring (Trolley 1/2 and 3/4)
30	Nov	09	TMM Stage 1 Commissioning Complete (Trolley 1/2 and 3/4)
31	Dec	09	Project Closure and Simplified Post Implementation Review

A Project Execution Plan (PEP) was not prepared for this project. Project Charter D-PCH-33160-10004 was issued in November 2006.

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%
Sept	2008	Vented Closure Plugs	1,500	12.5%
Mar	2009	Channel Isolation Plugs	1,200	8.8%
Mar	2009	Channel Isolation Plug Software Modification Upgrades	1,600	11.5%
Mar	2009	Trolley Mounted Magazine	5,225	37.6%

Attachment "D"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 months)	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges **OR** Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages **OR** Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

ONTARIOPOWER GENERATION

Darlington Fire Protection Upgrade - Phase III 16 - 79148

Superseding Business Case D-BCS-78000-10001-R005

1/ RECOMMENDATION:

We recommend:

1. The removal of Non REG C items from the scope of work (approximately $800k).
2. The release of an additional $6.2M, including contingency, for completion of the REG C scope of work.

The project met the Canadian Nuclear Safety Commission (CNSC) REG C commitment, A/R # 28030880, on December 30, 2005. Outstanding work to complete the project includes Available for Service actions, discovery work, and project close out activities. As of May 31, 2006 the project has spent $26.1M which exceeds the released funding of $23.5M. This unapproved expenditure of approximately $2.6M has been documented by SCR D-2006-03180 and reviewed by the ensuing B2 (detailed root cause) analysis.

In order to complete the REG C work by December 31, 2005 all Non REG C work such as the Inaccessible Smoke Detectors and Fire Works was deferred. It is now recommended that this Non REG C work be examined under a new stand alone project where a thorough review of needs will be conducted and lower cost alternatives (including do nothing) assessed.

A Superseding Business Case was signed by the Site Vice President, Darlington in December 2005; however, it has been subsequently revised to correct OAR elements and incorporate the latest cost estimates to complete Available for Service actions, discovery work, close-out activities, and cost over runs.

The revised cost estimate of $28.9M (excluding contingency) is $3783k more than the 2006-2010 Business Plan and $2400k more than the 2006 Budget. These variances will be addressed through the portfolio management process.

$000's (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	Full	20,591	2,475	422					23,488
Requested Now	Superseding	3,550	863	1,791					6,204
Future Funding Req'd	Choose								-
Total Project Costs		24,141	3,338	2,213	-	-	-	-	29,692
Ongoing Costs									-
Other Costs									-
Grand Total		24,141	3,338	2,213	-	-	-	-	29,692

Investment Type	Class	NPV or IEV	IRR	Discounted Payback
Regulatory	Capital	Not Applicable	Not Applicable	Not Applicable

Submitted By:

G.O.D. Smith
Senior Site VP - Darlington

Date: 5 Oct 2006

Finance Approval:

D. Power
Director, Investment & Business Planning

Date:

Line Approval (Per OAR Element 1.4 Variance):

J. Hankinson
President & CEO

Date: Mar. 9/07

2/ BACKGROUND & ISSUES

The Full Release Business Case Summary D-BCS-78000-10001 R004 for this project was approved on January 12, 2005 for $23.5M, including contingency. The project scope included resolution of Code Compliance Review (CCR) and Fire Safety Analysis (FSA) deviations, which was a CNSC REG C commitment, as well as Non REG C work.

The drive to meet the REG C committed date, productivity issues, as well as an underestimation of scaffolding costs and labor rates resulted in higher than estimated costs for the CCR/FSA Fire Detection Work Package of approximately $8.0M and for the Sprinkler & Standpipe Work Package of approximately $1.3M. This includes contractor over expenditures and Available for Service actions such as re-commissioning a part of the fire detection system. It also includes discovery work such as resolution of an engineering change breakthrough event associated with booster pump over pressure (SCR D-2006-00222) and Power House Annex issues and project close-out activities.

To limit the unapproved cost variance, all close-out activities have been placed on hold. Also, this variance has been partially offset by $1.6M due to creative solutions (see below) for other REG C work packages, reducing the number of devices installed by 16% (approximately $1.5M) and the drawing down of the project contingency of $2.5M.

An alternate resolution has been successfully negotiated and implemented for the Public Address (PA) system resulting in a saving of approximately $1.1M from the original estimate. The CNSC has been informed of the alternate resolution which consists of a system surveillance program where audibility and functionality of the PA system will be routinely monitored.

We have also successfully negotiated to retain the CO2 fire detection system "as is" and remove the CO2 extinguishing systems from the Darlington site except for the fuel storage tank rooms located inside the EPS-FM Building. CNSC has been informed of this alternate resolution. This has resulted in a saving of approximately $0.5M.

In order to complete the REG C work by December 31, 2005 and limit cost variances the Non REG C work was deferred. It is now recommended that the Non REG C work be removed from this project so that it can be evaluated in more detail under a separate project. The Non REG C work primarily relates to the resolution of inaccessible smoke detectors for inspection and maintenance, removal of obsolete smoke detectors, tie-in of bypass switch panel for ease of maintenance, resolution of existing main control room fire alarm re-flash annunciation issues, and installation of a fire panel graphical user interface (Fire Works). The detailed scope of work for a significant portion of this Non REG C work is not yet defined. Cost estimates to complete this work has escalated very significantly (from $0.8M in the original release to upwards of $4.5M). As the business objective is to reduce the current level of OPG staff effort required to perform periodic maintenance, a financial evaluation will be completed to assess lower cost alternatives.

See Attachment A, B and E for further detail.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Stop the Project	Alt 1 (Recommended)		Alt 2 Delay	Alt 3	Alt 4	Alt 5	Alt 5
		Full Cost	Incremental Cost					
Project Cost		29,692	6,204		34,192			
NPV (after tax)								
Impact on Economic Value		-	-	-	-	-	-	-
IRR%								
Discounted Payback (Yrs)								

Stop the Project - Not Recommended

Stopping the project is not recommended, since outstanding work associated with the REG C such as re-commissioning a part of the fire detection system, resolution of the booster pump over pressure issue, discovery work and project close-out activities would remain incomplete. This would run counter to the CNSC's expectation to resolve and close-out these items.

Alternative 1 - Do Less - Recommended

It is recommended that only the REG C work be completed under the scope of this project and that Non REG C items be removed from the scope of this project.

This allows for the completion of Available for Service actions, discovery work, and close-out activities associated with the REG C work. It also permits the re-evaluation of the needs versus wants and development of the detailed scope for the Non REG C work under a separate project so that an assessment of lower cost alternatives (including do nothing) is completed.

Alternative 2 - Delay Project - Not Recommended

CNSC verbally agreed to the completion of the December 31, 2005 REG C on the condition that all outstanding items are completed on an urgent basis. Delay of the project is not recommended, as it shows lack of commitment to the regulator and would disrupt project efficiency the close-out stage (incurring additional stop/start costs).

Alternative 3 – Complete Project within Original Plan - Not Recommended

The original plan was to complete the REG C and Non REG C work by December 31, 2005.

REG C committed work is to resolve deviations identified in the Darlington Code Compliance Review and the Darlington Fire Safety Assessment.

Non REG C work is associated with removal of obsolete smoke detectors, resolution of inaccessible smoke detectors for inspection and maintenance, tie-in of bypass switch panel for ease of maintenance, resolution of existing main control room fire alarm re-flash annunciation issues, and installation of a fire panel graphical user interface (Fire Works).

Completing the original plan is not recommended because the scope of the Non REG C work is not fully defined, the cost estimate of Non REG C work has escalated significantly and requires re-evaluation and review of the needs so that an assessment of lower cost alternatives (including do nothing) is concluded.

Alternative 4 – Do More - Not Recommended

The scope is based on recommendations provided in the Fire Protection Code Compliance Review and Fire Safety Assessment Reports. There is no plan or justification to increase the scope of work. In the event that the CNSC challenges any of the CCR/FSA resolutions previously submitted, new projects are to be created by the stakeholders as required to resolve these issues.

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

The proposal is for the:

1. Removal of the following Non REG C items from the scope of this project so that they can be reviewed and approved on their own merit under a separate project:
   a. Obsolete smoke detector removal.
   b. Inaccessible smoke detector resolution.
   c. Maintenance bypass panel.
   d. Control room fire alarm re-flash resolution.
   e. Fire Works installation.

2. Approval of funding for completion of REG C related items, specifically to:
   a. Cover the cost variance to May 31, 2006 of $2.6M (SCR D-2006-03180).
   b. Complete the following Available for Service actions:
      i. Work Package #2: Fire Suppression
         - Standpipe close-out.
      ii. Work Package #7: Fire Detection
         - Investigation of alarms in Local Unit Control Equipment Room (SCR D-2006-02283).
         - 3rd Party verification of duct detectors, pump annunciation, and door interlocks.
         - Removal of HVAC tie-in, pending CNSC approval.
         - Waste Handling Door spare parts review, drawing updates, Final AFS, and close-out.
         - Update and issue detection drawings/documentation.
   c. Complete the following discovery work:
      i. Work Package #1: Fire Doors, Seals, and Exit Signs
         - Unit 2 stairwell grating replacement design, installation, and close-out (SCR D-2006-01082).
      ii. Work Package #2: Fire Suppression
         - Booster pump over pressure resolution, design, installation, and close-out (SCR D-2006-00222).
      iii. Work Package #6: Fire Barriers, Power House Annex
         - Insulation and door replacement.
   d. Complete project close-out activities.

Refer to Attachment D for further detail.

Note that the REG C commitment has been met.

5/ QUALITATIVE FACTORS

This project will:

1. Increase safety to the public and to employees.
2. Improve the ability to prevent, contain, and minimize damage or loss of asset from fire.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Cost of Non REG C items exceeds the released funding.	Additional funding required.	**Medium**	Removal of Non REG C items from scope for re-evaluation and review of the needs under a separate unrelated project.	**Low**
Project cost exceeds estimate.	Additional funding required.	**Low**	Majority of work is close-out/clean-up. For 2 items with outstanding design it is > 50% complete, installation estimates obtained, and $655k specific contingency available for items with risk.	**Low**
Re-initiation of interest charges.	Additional funding required.	**Low**	Confirmed with Station Finance that Equipment In Service declaration is at 100%; hence, no further interest charges to the project.	**Low**
Scope				
Undefined scope for Non REG C items.	Additional funding required.	**Medium**	Removal of Non REG C items from scope for re-evaluation and review of the needs under separate unrelated project.	**Low**
Duct detectors do not meet performance requirements.	Increased cost due to duct smoke detector relocation/re-adjustment.	**Medium**	$110k specific contingency available for duct detector re-work & HVAC tie-in.	**Low**
Standpipe hangers and fittings do not meet performance requirements.	Increased cost due to standpipe hanger and fitting replacement.	**Medium**	$95k specific contingency available for replacement.	**Low**
Schedule				
Business case approval delayed.	Project completion date extended.	**Medium**	Project close-out activities put on hold. Risk remains MEDIUM until this business case is approved. Station (IPG) scheduling requirements to be followed upon project re-initiation.	**Medium**

Lack of CNSC confirmation on duct detector & HVAC tie-in proposal.	Unable to complete close-out of detection design package.	**Medium**	If no response received by December 2006 letter to be submitted in January 2007 to the CNSC stating that the proposal is assumed to be accepted due to lack of response and tie-in will be deleted.	**Low**
Redundant detection removal included in current design.	Unable to complete close-out of detection design package.	**Medium**	Close-out notes to include Action Tracking for new Non REG C project to remove detection.	**Low**
Resources				
Resources not available to support the outstanding work.	Project completion date extended.	**Medium**	Commitments obtained from Design, Field Engineering, and CMO. Station resources (Operations/Maintenance) will be acquired via IPG scheduling process.	**Low**
Technical				
Over pressure flow switch design not concurred to by 3rd Party.	Higher design/installation costs due to re-work. Project completion date extended.	**Medium**	$250k specific contingency avialable for re-design and $200k for installation of jockey pumps. Factory acceptance testing to validate design pior to scheduling field installation included in the estimate.	**Low**
Fire alarms in Local Unit Control Equipment Room (LUCER).	Increased operating cost due to municipal fire department visits. Increased cost for room clean-up and repair of damaged equipment not associated with the project.	**Medium**	Equipment operating as per design (i.e. sensing smoke/smoke like particles). Any repairs to smoke/fire damaged equipment or cleaning of the room to remove dust particles is outside the scope of this project.	**Low**
Door interlock operation not concurred to by 3rd Party.	Increased cost for room and HVAC repairs not associated with the project.	**Low**	Replicate standard room conditions, via temporary alteration of the HVAC, and repeat test to the 3rd Party to demonstrate interlock operation. Room/HVAC repairs is outside the scope of this project.	**Low**
Regulatory				
CNSC does not accept the dispositions to the standpipe, sprinkler, and other CCR/FSA deviations.	Additional work required to address CNSC concerns.	**Medium**	3rd Party Reviews submitted to CNSC, satisfying the license requirement. Estimate includes time for technical review of CNSC challenges. Probability of not resolving challenges is low. Disposition of any future unresolved challenges is outside the scope of this project. New projects (approx. $6M) to be initiated by stakeholders as required.	**Low**

CNSC requests duct detector & HVAC tie-in.	Increased cost to complete duct detector & HVAC tie-in.	**Medium**	$110k specific contingency available for duct detector re-work & HVAC tie-in.	**Low**
Environmental				
Poor installation and commissioining practices.	Release to environment.	**Low**	Compliance to corporate and nuclear environmental procedures.	**Low**
Health & Safety				
Unsafe labour practices.	Personal injury.	**Low**	Compliance to corporate and nuclear health and safety procedures.	**Low**
Investment				
Modifications do not work as planned.	Higher costs.	**Medium**	Industry experts/3rd Parties used during design, installation, and commissioning to supplement OPG experience.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jun 2007	Dec 2007	Manager, Performance Engineering

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Resolve/disposition all CCR and FSA deviations	No deviations resolved at start of project	3rd Party concurrence of all resolutions and dispositions to CCR and FSA deviations	Written 3rd Party acceptance	Manager, Performance Engineering (Project Sponsor)
2.	Completion of Available for Service (AFS) for CCR and FSA modifications	No modifications completed at start of project	AFS acceptance of modifications by December 31, 2005	AFS acceptance meetings	Manager, Design Projects (Project Owner)
3.	Complete CNSC REG C Commitment A/R 28030880	REG C due date of December 31, 2005 at start of project	REG C commitment met by December 31, 2005	Completion letter submitted to CNSC	Manager, Regulatory Affairs
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

AFS: Available for Service
A/R: Action Request
BCS: Business Case Summary
B&M: Black & McDonald, installation contractor
CCR: Code Compliance Review
CD: Crossby Dewar, installation contractor
CMO: Contract Management Office
CNO: Chief Nuclear Officer
CNSC: Canadian Nuclear Safety Commission
CO2: Carbon Dioxide, inert gas based fire suppression system
CSA: Common Secondary Area
DCP: Design Change Package
EC: Engineering Change
EPS: Emergency Power Supply
EPS-FM: Emergency Power Supply - Fuel Management
EST: Edwards Systems Technology, manufacturer of fire panels & fire protection equipment
EST-3: Fire Panel model supplied by Edwards Systems Technology
FFAA: Fueling Facility Auxiliary Area
Fire Works: Graphical user interface to EST-3 fire panels by Edwards Systems Technology
FSA: Fire Safety Analysis
HVAC: Heating, Ventilation, and Air Conditioning
IRR: Internal Rate of Return
LTD: Life to Date
LUCER: Local Unit Control Equipment Room
MOCPER: Main Output Control and Protection Equipment Room
N/A: Not Applicable
NPV: Net Present Value
OAR: Organizational Approval Registry
OM&A: Operating, Maintenance, and Administration
OPEX: Operating Experience
OPG: Ontario Power Generation
PA: Public Address
PHA: Power House Annex
PHT: Primary Heat Transport
PIR: Post Implementation Review
PMOD: Permanent Modification
REG C: Type of CNSC regulatory commitment
SCA: Secondary Control Area
SCR: Station Condition Record
TMOD: Temporary Modification
VESDA: Very Early Smoke Detection Apparatus, air sampling based smoke detection system by Edwards
WTP: Water Treatment Plant

Appendix "B" **Project Funding History**

$ 000's			Cumulative Funding								
Release Type	Month	Year	2001	2002	2003	2004	2005	2006	2007	Later	Total
Developmental	Nov	2000	100								100
Partial	Aug	2001	1,470	430							1,900
Interim	May	2002	1,470	930	1,000						3,400
Interim	Feb	2004	1,470	930	1,000	3,800					7,200
Full	Jan	2005	1,470	930	1,000	3,945	13,246	2,475	422		23,488
Superseding	Aug	2006	1,470	930	1,000	3,945	16,796	3,338	2,213		29,692
LTD Spent	May	2006	1230	813	1412	3906	16780	1933			26,074

Comments:

Appendix "C"

Financial Model – Assumptions

Project Cost Assumptions:

Not applicable.

Financial Assumptions:

Not applicable.

Project / Station End of Life Assumptions:

Not applicable.

Energy Price / Production Assumptions

Not applicable.

Operating Cost Assumptions

Not applicable.

Other Assumptions:

Darlington Fire Protection Upgrade - Phase III 16 - 79148

Superseding Business Case D-BCS-78000-10001-R005

Attachment "A"

Project Cost Summary

$000's Capital	Work Package	LTD Prior Years 2005	2006	2007	2008	Total	LTD This Mth May 2006	LTD %
Project Management	All	2,576	531	434	-	**3,541**	2,918	**82.4%**
Detailed Eng	All	5,466	830	47	-	**6,343**	5,726	**90.3%**
Fire Doors, Seals, & Exit Signs	1	319	8	37	-	**364**	327	**89.8%**
Fire Suppression	2	1,915	575	483	-	**2,973**	2,453	**82.5%**
Stairwell Enclosures	3	1,141	-	-	-	**1,141**	1,141	**100.0%**
Emergency Lights	4	46	-	-	-	**46**	46	**100.0%**
Public Address Fire Alarm	5	88	-	-	-	**88**	88	**100.0%**
Fire Barriers - Powerhouse Annex	6	105	64	-	-	**169**	169	**100.0%**
Fire Barriers - PHT Pumps	6	50	-	-	-	**50**	50	**100.0%**
Radiant Energy Fire Barriers	7	644	-	-	-	**644**	644	**100.0%**
CO2 Fire Detection	7	-	-	-	-	**-**	-	**0.0%**
Inaccessible Detectors/Removal	7	67	-	-	-	**67**	67	**100.0%**
Fire Works	7	-	-	-	-	**-**	-	**0.0%**
CCR/FSA Fire Detection	7	10,371	732	149		**11,252**	10,926	**97.1%**
Procedures	8	-	-	-		**-**	-	**0.0%**
Interest	All	1,128	98	-	-	**1,226**	1,226	**100.0%**
Close-out	All	49	500	233	-	**782**	117	**15.0%**
Overhead	All	176	-	-	-	**176**	176	**100.0%**
Sub total (REGC)		24,141	3,338	1,383	-	28,862	26,074	**90.3%**
General Contingency	All			175		175	-	**N/A**
Specific Contingency	2 & 7	-	-	655		655	-	**N/A**
Grand Total		24,141	3,338	2,213	-	29,692	26,074	**N/A**
Ongoing OM&A								
Inventory Write Off Required								
Spare Parts / Inventory								
Grand Total (incl contingency)		24,141	3,338	2,213	-	29,692	26,074	
2006-2010 Business Plan		24,141	938	-	-	25,079	**N/A**	**N/A**
Variance to Business Plan (excl conting)		-	(2,400)	(1,383)	-	(3,783)	**N/A**	**N/A**

Specific Contingency:
$250k for redesign of Booster Pump over pressure resolution (Work Package #2: Fire Suppression)
$200k for installation of redesigned Booster Pump over pressure resolution (Work Package #2: Fire Suppression)
$95k for hanger and fitting replacement (Work Package #2: Fire Suppression)
$110k for duct detector re-work and HVAC tie-in (Work Package #7: Fire Detection)

Basis of Estimate					
Design Complete	Up to ~40%	Contracts in place	No	Competitive Bid	N/A
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Sponsor Cost Estimate	N/A	Phase 1 Actual Used	Yes

Other:

Reviewed By:

Ken. Piggott

R. Piggott
Project Manager

Date: 15/09/06

Approved By:

Terry Chong

T. Chong
Eng & Mods Manager (Strat IV)

Date: 15 Sept 2006

ONTARIOPOWER GENERATION

Darlington Fire Protection Upgrade - Phase III 16 - 79148

Superseding Business Case D-BCS-78000-10001-R005

Attachment "B" **Project Variance Analysis**

$000's Capital	Work PKG	Last Release 12-Jan-05	This Release 31-Aug-06	Variance	LTD May-06	Out Standing	Explanation
Project Management	All	3,422	**3,541**	119	2,918	623	Additional oversight required for remaining open items.
Detailed Engineering	All	6,118	**6,343**	225	5,726	617	Includes $739k for PA design that was not required for resolution of CCR deviation.
Fire Doors, Seals, & Exit Signs	1	364	**364**	-	327	37	Additional cost due to Unit 2 stairwell grating repair/replacement discovery work.
Fire Suppression	2	1,710	**2,973**	1,263	2,453	520	Increased installation cost for Standpipe Booster Pump due to schedule delays and installation overtime to meet REG C date. Increased cost due to resolution of EC breakthrough event. Part of the cost increase was offset via an alternate resolution to retain the sprinkler system "as is" for the East and West FFAA areas.
Stairwell Enclosures	3	1,061	1,141	80	1,141	-	Increased cost due to schedule delays.
Emergency Lights	4	167	46	(121)	46	-	Alternate resolution implemented to satisfy REG C commitment; thus, reduced scope and cost.
PA Fire Alarm	5	1,234	**88**	(1,146)	88	-	Alternate resolution implemented to satisfy REG C commitment; thus, reduced scope and cost.
Fire Barriers - PHA	6	41	169	128	169	-	Discovery work to resolve design weakness and upgrade wall to meet fire rating requirement.
Fire Barriers - PHT Pumps	6	120	**50**	(70)	50	-	Efficient installation by contractor.
Radiant Energy Fire Barriers	7	254	**644**	390	644	-	Under estimated installation. Part of the cost increase was reduced by installing smoke detection in lieu of fire barriers as a result of a lessons learned.
CO2 Fire Detection	7	516	-	(516)	-	-	Alternate resolution implemented to retain the fire detection system "AS IS" to satisfy REG C.
Inaccessible Detectors	7	578	**67**	(511)	67	-	Non REG C work to be removed from project scope for evaluation under a separate unrelated project.
Fire Works	7	225	-	(225)	-	-	Non REG C work to be removed from project scope for evaluation under a separate unrelated project.
CCR/FSA Fire Detection	7	3,260	11,252	7,992	10,926	326	Productivity rate exceeded (72 hrs/device vs. 26 hrs/device), use of scaffold instead of ladders ($1.9M vs. $0.7M), change to contractors from direct hires ($78/hr vs. $55/hr), CMO ($0.4M vs. $0.0M) and additional Field Engineering ($0.6M vs. $0.1M).
Procedures	8	100	-	(100)	-	-	Completed outside the project by base resources.
Interest	All	1,181	1,226	45	1,226	-	In service delays.
Close-out	All	473	**782**	309	117	665	High number of field changes, discovery items, and inclusion of Design review during close-out.
Overhead (prior 2004 Charges)	All	176	**176**	-	176	-	
Sub Total		21,000	28,862	7,862	26,074	2,788	
Contingency		2,488	830			830	Full release contingency of $2,488k used, additional $830k requested going forward.
Grand Total		23,488	29,692	6,204	26,074	3,618	

Comments:

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
08	June	2007	Unit 2 Grating Replacement - AFS
25	June	2007	Booster Pump Over Pressure Resolution - AFS
21	Dec.	2007	Project Complete

Comments:

Attachment "D"
Scope of Work and Status

	Scope of Work	Status/Outstanding Items
Work Package #1 Fire Doors, Seals and Exit Signs	Modify/replace non-code compliant fire doors. Inspect/repair fire rated barrier seals and penetrations in the exit stairwells. Install exit signs as per fire code requirements.	Discovery work: Unit 2 floor grating replacement design, installation, and close-out.
Work Package #2 Fire Suppression	Sprinklers: 1. Install 5 additional sprinklers heads in the CSA Stores. 2. Restrict height of material in the storage racks. 3. Sprinkler upgrades in the East and West FFAA. Standpipe: Complete hydraulic calculations of Standpipe System. Resolve deficiencies: low system pressure, additional fire hose connections, relocate fire hose cabinets, etc.	Sprinklers: 1. Complete 2. Complete 3. Complete, sprinklers kept "as is". Standpipe: AFS action: Documentation close-out. Discovery work: Booster pump over pressure issue.
Work Package #3 Stairwell Enclosures	Upgrade the eight Turbine Hall stairwell enclosures on the 115 m elevation to the required fire rating.	Complete
Work Package #4 Emergency Lights	Part A: Upgrade the emergency lighting in the WTP and Pump Houses. Part B: Provide handheld portable lights for Operation staff.	Part A: Complete Part B: Complete
Work Package #5 Public Address Fire Alarm	Perform technical evaluation for the continued use of the PA system as an alternate disposition for fire alarm notification. Seek concurrence from the 3rd Party Reviewer and inform CNSC.	Complete
Work Package #6 Fire Barriers	PHA: Correct deficiencies in the powerhouse annex link to Unit 4. PHT Pumps: Install dikes at entrance to PHT pump rooms.	PHA: Discovery Work: Insulation/door replacement and close-out. PHT Pumps: Complete
Work Package #7 Fire Detection	Part A: Install detection in LUCER/MOCPER/SCA. Install Bypass Switches (Non REG C) to facilitate maintenance on fire detection EST-3 system. Part B: Install Radiant Energy fire barriers to protect affected cable pans identified in the FSA deviation report. Part C: 1. Install fire detection and pull stations in various locations to resolve CCR and FSA deviations. 2. Inaccessible Detectors (Non REG C): Assess and seek alternate disposition to make approximately 340 smoke detectors accessible for routine maintenance and testing. Part D: Install Fire Works (Non REG C) to interface with the EST-3 fire panels.	Part A: Complete AFS follow up action: Investigation of VESDA alarms (Unit 1 & 4 LUCERs). Bypass Switches (Non REG C): To be removed from project. Part B: Complete Part C: 1. Complete AFS follow up actions: • 3rd Party verification of duct detectors, pump annunciation, and door interlocks. • Waste Handling Door spares review, drawing update, Final AFS, and close-out. • Pending CNSC approval, remove HVAC tie-in. • Issue documentation/drawings. 2. Inaccessible Detectors (Non REG C): To be removed from project. Part D: Fire Works (Non REG C): To be removed from project. Scope has grown to include resolution of an existing fire alarm re-flash annunciation issue.

	Scope of Work	Status/Outstanding Items
Work Package #7 Fire Detection (Continued)	Part E: Review and seek alternate resolution to disposition the CCR deviations relating to inappropriate fire detector location, lack of pull stations, lack of pre-discharge and discharge alarms inside the CO2 protected areas. Part F: 1. Modify breaker interlock. 2. Re-route EVEN EPS bus related cables.	Part E: Complete Part F: 1. Complete, no modification required. 2. Complete, no modification required.
Work Package #8 Fire Protection Procedures	1. CCR Deviation: Revise the identified fire protection inspection, testing and maintenance procedures to comply with the fire codes. 2. FSA Deviation: Revise and issue Operating Procedure for Emergency Response Manual Fire Actions by Authorized Nuclear Operator.	1. Complete 2. Complete

Attachment "E"

Outstanding Scope/AFS Actions/Discovery Activities

Item	Forecast ($000's)	Notes
Unit 2 Stairwell Grating Modification	87	Discovery work – Design, implementation, and close-out outstanding.
Booster Pump over pressure resolution	768	Discovery work – TMOD implemented. PMOD design, implementation, and close-out outstanding.
PHA Door AFS & close-out	20	Discovery work – Combustible insulation removal and fire door replacement completed, AFS and close-out outstanding.
3rd Party verification & VESDA investigation	193	AFS Action – 3rd Party verification of detection and investigation of alarms in Unit 1 and Unit 4 LUCERs.
Waste Handling Doors	55	AFS Action – Spares review, drawing update, and Final AFS outstanding.
Duct Detection/HVAC tie-in deletion	182	AFS Action – Pending CNSC approval, de-engineer HVAC tie-in via DCP revision and remove affected cabling from the field.
Standpipe close-out	309	AFS Action – Contractor and documentation close-out outstanding.
Detection close-out	552	AFS Action – Contractor and documentation close-out outstanding.
Project Management	622	Oversee completion of remaining activities.
Contingency	830	General Contingency: $175k Specific Contingency: $250k redesign of Booster Pump over pressure resolution $200k installation of redesigned Booster Pump over pressure resolution $95k for hanger and fitting replacement $110k for duct detector relocation and HVAC tie-in
Total	**3,618**	

PNGS-A D2O Storage and Drum Cleaning Facility 13 - 49251

Developmental Release Business Case Summary NA44-BCS-38000-00001-R000

1/ RECOMMENDATION:

We recommend approval of a Developmental Release of $2,506k (including [redacted] contingency) to complete preliminary design, initiate detailed design, initiate Requests for Quotations for long-lead materials and develop a Partial Release for the PNGS D_2O Storage and Drum Handling Project by November, 2007. A Partial Release will be requested upon completion of preliminary engineering to facilitate a seamless transition to detailed design, long-lead material procurement, initiate Requests for Proposal for the construction contract and develop the Full Release. This funding strategy will minimize cost and schedule delays.

There are three business objectives of this project as per Project Charter N-PCH-03800-10000:

1. Improve detritiation capability within OPG-N
2. Provide operational flexibility for the storage and segregation of different grades of D_2O
3. Provide a drum cleaning facility to manage the backlog of D2O drums in the station

Note: Plant Life Extension and Decommissioning of P2 and P3 are not part of the mandate of this project.

Kinectrics was commissioned to study the Heavy Water Storage and Drum Handling issues from the overall OPG-N perspective. The recommended modification for Pickering is listed below:

- Install 1x 16 Mg downgraded, low curie, oily D_2O tank
- Install 1x 16 Mg downgraded, high curie, oily D_2O tank
- Install 1 x 46 Mg downgraded, low curie, non-oily D_2O tank
- Install 1 x 19 Mg downgraded, high curie, non-oily D_2O tank
- Install a Drum Cleaning Facility

Detritiation difficulties at PNGS cannot be solely tied to a lack of storage capacity at the Storage and Inventory (S&I) system and, therefore, it is not recommended any S&I tanks to be installed in PNGS. However, Pickering will be able to utilize Darlington's S&I tanks, that are to be installed under Darlington Project 16-31555, as temporary storage as required or TRF product reservoirs to ensure low curie D_2O is always available to Pickering for detritiation. Similarly, there is insufficient justification to install a drum cleaning facility at DNGS and that the Pickering's Drum Cleaning Facility will be used to clean dirty drums from Darlington.

Choose One	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	None								-
Requested Now	Developmental			1,330	1,176				2,506
Future Funding Req'd					2,837	7,720	4,319		14,876
Total Project Costs		-	-	1,330	4,013	7,720	4,319	-	17,382
Other Costs									-
Ongoing Costs									-
Grand Total		-	-	1,330	4,013	7,720	4,319	-	17,382
Investment Type		Class		(IEV) Impact on Ec Value		IRR		Discounted Payback	
Sustaining		Capital		6,473		14.7%		7.8	

Submitted By:

27-Nov '06

Rumina Velshi
Director, Commercial Activities
Project Sponsor

Date:

Finance Approval:

Nov. 27 2006

Randy Leavitt
Director, Investment Management, NOSS

Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Nov 29/06

Martin Tulett
Director, Operations & Maintenance, Pickering

Date:

2/ BACKGROUND & ISSUES

Both Pickering Nuclear Generating Station A and B need to improve their overall ability to manage D_2O inventories to support continuous station operations in a safe and cost efficient manner. In December 2004, Kinectrics Inc. was requested to perform a strategic study on OPGN's Heavy Water Storage and Drum Handling Strategy. (Ref; K-011043-001-RA-0001-R00A). In April 2006, Kinectrics Inc. was engaged by the Project to fine-tune the initial study with clear assumptions and verified information for the stakeholders

The three main objectives of this project are as follows:

1. Allow large volume bulk swap of heavy water for detritiation to keep units running below the OP&P limit for tritium concentration.
2. Improve operational flexibility to segregate different streams of D2O to support normal operation and outages.
3. Improve the management of drums in the station and to reduce associated drum handling-related radiological and conventional safety hazards.

Decommissioning of P2 and P3 and Plant Life Extension are not part of the mandate of this project.

2.1 Large Volume Bulk Swap of Heavy Water for Detritiation

Pickering B units have exceeded their Administrative limits for tritium concentrations in both the Moderator and the Primary Heat Transport (PHT) system and are fast approaching the OP&P limits.

The current mode of detritiation is performed with the reactors online whereby high Curie Moderator D_2O is bled out from the unit and low Curie D_2O is fed from the Storage and Inventory System (S&I) into the unit simultaneously.

The preferred mode of detritiation of the station is to perform bulk detritiation on a unit during outages when the Moderator inventory is drained out and replaced by the same volume of low Curie D_2O which is often of a higher isotopic. As a result, the isotopic of the Moderator system is upgraded simultaneously. This mode of detritiation is opportunistic and requires more tanks for D_2O maneuvering; however, it is more effective since there will be no wastage of the low Curie D_2O being fed to the unit.

The following tables summarize the problems that are caused by the inability to perform large volume bulk swaps of D_2O for detritiation:

Table A. Problems caused by inability to perform large volume bulk swaps of D_2O for Detritiation

Problem	Issues	Impacts
There is inadequate Storage and Inventory (S&I) storage capacity to allow large volume bulk swap to be performed readily	• Reliance on online detritiation, as there is very limited capability to perform the more effective offline detritiation. • Require extensive planning and coordination with TRF and rearranging D_2O in S&I Tanks, even for on-line detritiation • Inability to efficiently perform moderator upgrading	• Less efficient reduction of tritium emissions to the environment • Less efficient reduction of dose absorbed by workers • Possibility of regulatory sanctions due to OP&P violations as a result of a lower efficiency of detritiation • Lower fuel-burnup efficiencies

2.2 Operational Flexibility to Segregate Different Streams of D_2O

The lack of storage capabilities for proper segregation of different streams of D_2O inventory is impairing operations. If off-site storage is required, or if operator work-arounds are warranted, then this increases costs and induces additional workload for operations

2.2.1 Reactor Grade D_2O Storage & Segregation

During normal or outage situations, the following inventories of D2O should be segregated:

- High Curie D_2O (including Sulzer-B Upgrader Product)
- Low Curie D_2O (including UPP-B Upgrader Product)
- Moderator D_2O (containing Gadolinium)
- Primary Heat Transport D_2O (contains Lithium)
- TRF Grade D_2O (Very Low Curie)

The following table summarizes the problems that are caused by not having enough Reactor Grade D_2O (S&I) Tanks for storage and segregation:

Table B. Problems caused by insufficient S&I tanks for Reactor Grade D2O Storage and Segregation

Problem	Issues	Impacts
Limited flexibility in reactor grade D_2O segregation during outages	• During outages, when S&I tanks are taken up by moderator drains or PHT drains, then the existing inventory does not have space for storage	• Pickering Incoming/Outgoing D_2O Transfer System (PIOTS) is often used to store Reactor Grade D2O during outages, impeding TRF receiving and shipping activities • When S&I tanks are taken up by drains from the outage unit, there is limited capacity to hold upgrader products from Sulzer-B or UPP-B, causing these upgraders to go into reflux • High probability of human performance errors when tanks that were specified to hold a certain grade of D_2O must be filled with another grade of D_2O due to lack of storage space
Limited flexibility to store assigned TRF product's quota to meet PNGS's Detritiation Plan	• Shipment and receiving of TRF Product rely heavily on the availability of TRF and S&I • Requires planning and resources to rearrange contents in S&I before shipping and receiving	• Reduce capability to meet PNGS's detritiation plan

2.2.2 Downgraded D_2O Storage & Segregation

The existing storage capacity at the Ion Exchange Clean-Up System (IXCU) is not adequate for segregating downgraded D_2O. The following grades of downgraded D_2O should be segregated for maximum IXCU operating efficiency:

- High Curie, Non-Oily D_2O
- Low Curie, Non-Oily D_2O
- High Curie, Oily D_2O
- Low Curie, Oily D_2O

Table C. Problems caused by insufficient IXCU tanks for Downgraded D_2O Storage and Segregation

Problem	Issues	Impacts
The original design of the IXCU system is not adequate for the current recovery rates	System Degradation, causing high leakage rates and a high load on recovery and clean-up systems	• When the load cannot be efficiently processed by the IXCU system, a large amount of backlog is accumulated, requiring all recoveries to be drummed, increasing drum handling, dose hazards and housekeeping issues
The IXCU system was not designed for high volumes of oily D_2O recoveries.	The Pickering fuelling machines leaks a hydraulic fluid which is collected in the Building Liquid Recovery system.	• Any backlogged oily D_2O is drummed, causing drums to become oily. • Oily recoveries may overflow into non-oily tanks, causing these tanks to become oily as well, contaminating clean recoveries. This further increases the oily load. • Additional expenses need to be incurred to clean the oil film off of the non-oily tanks every few years. • Oily recoveries process at a slower rate than non-oily recoveries, lowering the efficiency of the IXCU system. • Inadvertent leakage of oily recovery into the upgraders is a contributing factor to the degradation of upgrader's packing and to the reduction of heat transfer capability of the reboilers. • External upgrading services will be expensive and repacking of upgraders will cost millions.
IXCU was not designed to treat or segregate High TOC D_2O.	• Use of organic solvents and chemicals in the Reactor Building for cleaning and reactor components inspections causes high Total Organic Carbon (TOC) levels in recoveries • TOC is very difficult to remove and it requires sufficient time and segregation to be reduced to less than 1 ppm before they can be sent to the upgraders to prevent upgrader packing degradation and plugging of distributors.	• The degradation of upgraders due to TOC may be exacerbated to a point where external upgrading services are required. • Inadequate feed to the upgraders due to the inability to achieve specifications causes backlog at IXCU, while the upgraders to go into reflux, wasting operational resources • If a significant inventory cannot be upgraded, then the D2O must be made up from D2O rentals from external companies *Note: It is assumed that a UV-Oxidation Unit will be installed in Pickering, which is capable of reducing TOC from downgraded D_2O to the specified 1 ppm. The UV-Oxidation unit is designed to act as a polishing system to remove TOC after the majority of the contaminants are clean-up from the downgraded D_2O.*

2.3 Drum Cleaning Facility

Table D. Problems caused by a lack of a Drum Cleaning Facility

Problems	Issues	Impacts
Inability to process or reduce drum inventory	• Pickering has an inventory of 3000 drums around the station. • Oily drums being used to collect non-oily recoveries	• Drums that contain sludge cannot be disposed of • Housekeeping concern that has already instigated CNSC scrutiny • Drum Handling Hazards • Dose hazards • Takes up valuable real estate in the station • IXCU efficiency is reduced, causing a further backlog upstream, requiring the purchase of more drums to store the backlog @ $700 to $800/drum • If the inventory of unprocessable D_2O becomes too large to handle, then external cleaning services needs to be purchased

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$000's	Do Nothing	Alt 1 (Recommended)		Alt 2	Alt 3
		Full Cost	Incremental Cost		
Revenue	0	0	0	0	3,573
OM&A	(68,296)	(19,132)	(19,132)	(27,203)	(19,107)
Capital	0	(17,384)	(17,384)	(18,442)	(36,000)
NPV (after tax)	(26,817)	(20,344)	(20,344)	(22,985)	(32,390)
Impact on Economic Value (IEV)	N/A	6,473	6,473	3,832	(5,573)
IRR%	N/A	14.7%	14.7%	14.1%	N/A
Discounted Payback (Yrs)	N/A	7.75	7.75	7.96	N/A

Status Quo - Not Recommended

Status Quo is not a recommended option.

Pickering units need to achieve better detritiation efficiency in order to prevent reaching the OP&P limits for tritium content.

During normal operation, online detritiation performed in a large volume requires careful planning, coordination with TRF and movement of Reactor Grade D_2O in S&I tanks. This is due to the limitation of S&I tank storage space, which sometimes prevents online detritiation to be executed.

During outages, the receiving and shipping of TRF product is often impeded by the available S&I tank space, causing the station to miss valuable opportunities to detritiate.

The downgraded D_2O storage capability is not sufficient to meet current recovery rates, causing excessive drum usage that induces radiological and conventional hazards for workers. The lack of sufficient segregation of downgraded D_2O has caused the IXCU system to run below optimal efficiency, limiting the input to the upgraders. Engineering – Common Services has indicated that if IXCU tanks were not provided to them by 2014, then upgrader packing replacement would be inevitable. Packing replacement is an extensive overhaul to the upgrader and can cost over $10M. During the years where the flowrates of the upgraders can no longer meet its demand, external upgrading services will need to be purchased, costing over $1.3M for every 10kg/h variance, per year.

The drum problem is further exacerbated by the fact that Pickering has no capability to clean dirty drums, causing a housekeeping and dose issues that has drawn scrutiny from the CNSC.

Alternative 1 -
Install Additional Downgraded Storage Tanks and a Drum Cleaning Facility - Recommended

The recommended modification for Pickering is listed below:

Type of Tank	Size/Specifications	Location
Downgraded, low curie, oily D_2O tank	1 x 16 Mg	IXCU area, 274' el., RAB
Downgraded, high curie, oily D_2O tank	1 x 16 Mg	IXCU area, 274' el., RAB
Downgraded, low curie, non-oily D_2O tank	1 x 46 Mg	IXCU area, 274' el., RAB
Downgraded, high curie, non-oily D_2O tank	1 x 19 Mg	IXCU area, 274' el., RAB
Drum Cleaning Facility	Capable of cleaning a minimum of 10 drums/day	Between Solid Waste Handling Facility and PIOTS, 254' el., Service Wing

As a result of more rigorous review of the project needs vs. wants, the scope of the recommended option is leaner than that requested at the original project charter.

Installing additional downgraded storage tanks at IXCU and a drum cleaning facility will allow for the following (which are aligned with the project objectives):

1. Provide additional storage and segregation capability for downgraded D_2O to meet current recovery rates
   - Slow down degradation rates of upgraders to mitigate/delay costs to purchase external upgrading services
   - Mitigate costs to clean up oil-film build-up in non-oily tanks due to lack of proper segregation capability
   - Reduce the number of man-hours spent on tank maneuvering and backlog processing
2. Prevent the excessive use of drums
   - Reduce drum handling-related radiological and conventional hazards
   - Reduce the number of man-hours spent on drum handling
3. Allow Pickering and Darlington to clean oily drums
   - Prevents the use of oily drums to collect non-oily water
   - Reduce the number of drums in the station that are taking up valuable real estate
   - Mitigate costs to purchase external downgraded D_2O cleaning services.

The final recommendation does not include S&I tanks for the following reasons:

Since 1997, it was evident that "feed and bleed" detritiation has not been consistently performed. This increase in PNGS-B tritium concentration can be partially attributed to the lack of sufficient storage capacity for reactor grade D_2O at the S&I system. In addition, there are other factors that had contributed to this issue:

- Extended Tritium Removal Facility (TRF) outages which limited the amount of TRF product available for detritiation
- One 150 Mg S&I tank occupied with Gadolinium-D_2O for two years as a result of a previous attempt to perform bulk detritiation
- D_2O from Unit 4 Return-To-Service occupying S&I tanks
- Procedural issues associated with the safe execution of swaps that required 6-9 months to resolve
- Planning and resource coordination problems in shipments of D_2O to and from the TRF
- Detritiation can only be performed on weekends when the unit is in quiet mode

The additional S&I tanks installed at Darlington, as part of their D_2O Storage Project 16-31555 can alleviate Pickering's reliance on the availability of the TRF and can improve Pickering's opportunity to perform large volume bulk swaps. These tanks will act as temporary storage and TRF product storage tanks for Pickering when Darlington does not needs these tanks during outages. The utilization of Darlington's tanks in Pickering represents an additional investment mitigation of $18.6M.

Alternative 2 - Delay Project - Not Recommended

Delaying the project is **not** a recommended option. There is insufficient storage and segregation capability for downgraded D_2O since the recovery rates of downgraded D_2O have been increasing and the number of acute leakage events has been escalating. This causes backlog of recoveries that requires excessive drumming operations that may require more drum purchases. The number of drums in the station has already been causing housekeeping and dose issues that has drawn scrutiny from the CNSC. The backlog of drums maybe further aggravated when oily recoveries overflow to non-oily tanks causing clean recoveries to be contaminated with oil. Since oily D2O processes at a slower rate at the IXCU trains, this creates a vicious cycle of additional drum usage.

Furthermore, Engineering – Common Services has indicated that if IXCU tanks were not provided to them by 2014, then upgrader packing replacement would be inevitable. Packing replacement is an extensive overhaul to the upgrader and can cost over $10M. During the years where the flowrates of the upgraders can no longer meet its demand, external upgrading services will need to be purchased, costing over $1.3M for every 10kg/h variance, per year.

Alternative 3 –
Install Pickering's own Storage and Inventory Tanks, Install Additional Downgraded Storage Tanks and a Drum Cleaning Facility - Not Recommended

Although installing additional S&I tanks will benefit Pickering station by increasing its flexibility in storing and segregating reactor grade D2O, this is **not** a recommended option. Kinectrics has suggested that the inability to detritiate or improve moderator isotopics effectively over the last 10 years at Pickering cannot be solely tied to a lack of storage capacity at S&I. Although installing Pickering's own S&I tanks improves Pickering ability to detritiate and increase moderator's isotopic, the savings from dose reduction and better fuel burn-up cannot recover the investment required to complete this modification before end-of-life of the Pickering A and B units.

The total cost to implement this option is $36.0M, including contingency, with a +60%/-40% accuracy.

Alternative 4 – - Not Recommended

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

This Developmental Release of $2,505K (including contingency) will be used to complete the following deliverables:

- Provide project management support
- Provide OPG Design Support
- Prepare and award a Design Contract for Preliminary and Detailed Design
- Complete Preliminary Design (up to 40% Detailed Engineering)
- Issue Technical Specifications for Long-lead materials
- Review/Approve Preliminary Design
- Initiate Detailed Design
- Prepare Preliminary PEP
- Issue a Partial BCS

Refer to Appendix C for a list of the project milestones.

5/ QUALITATIVE FACTORS

Benefits to the Community/Regulator Relations

- Lower Tritium Emissions by using Darlington S&I tanks (Project 16-31555) to alleviate Pickering's reliance on the availability of the TRF, thereby ensuring a readily available supply of low curie product to detritiate Pickering's units.
- Eliminate scrutiny from CNSC of Pickering's tritium emissions

Health and Safety

- Effective utilization of the IXCU system will reduce the backlog of downgraded D2O in drums, reducing the occurrences of drum handling-related safety issues
- Clean drums can be re-used or disposed of to improve housekeeping in the stations

Operational Considerations

- Reduce operator workarounds, lowering the probability of human-performance errors

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Overall project cost exceeds current estimate.	Unable to accomplish all project objectives without futher release of funds	High	Detailed conceptual study completed by Kinectrics. Helyar review of project cost. Adopt optimal contracting strategy to mitigate cost escalation. Further fine tuning of overall project schedule and costs in a Partial BCS.	Medium
Fine tuning of contracting strategy & changes to funding release strategy may impact overall cost and schedule	Delay project schedule and increase costs.	High	Obtained agreement with line management on present funding strategy. Contracting strategy and design/installation requirements will be reviewed with Supply Chain, Procurement, Design and Legal.	Medium
Scope				
Unknown cost justification information not submitted to Projects causing cost and schedule impacts.	Rework will be required to evaluate impact of additional cost justification on preferred option. Additional costs and delays will be incurred.	Medium	Rigrous communication with stakeholders prior to submission of BCS to ensure that all cost justification information have been submitted.	Low
Preliminary Design/Detailed Design may result in an increase in scope.	Changes in scope results in delays in schedule and additional cost to the project.	Medium	Scope has been clearly defined, communicated, and agree to by stakeholders. Design will be reviewed and challenged by OPG.	Low
Schedule				
Schedule for completing contractor selection may be delayed due to rigorous management, supply chain and legal reviews of the RFP.	Schedule delay.	High	Reviewed OPEX & had adjusted schedule to allow more time. Early Supply Chain involvement to ensure that the tendering process for the contract is completed as soon as possible.	Medium
Fine tuning of contracting strategy & changes to funding release strategy may impact	Delay project schedule and increase costs.	High	Obtained agreement with line management on present funding strategy. Contracting strategy and design/installation requirements	Medium

overall cost and schedule			will be reviewed with Supply Chain, Procurement, Design and Legal.	
Insufficient information to determine the timeline of design deliverables accurately, and design deliverables may not be on time	Delay to Schedule	Medium	Finetuning of final design deliverable timeline is available via partial BCS. Select approved vendor, provide clear scope and deliverables, review progress regularly. Establish and monitor effective design performance metrics.	Low
Resources				
Insufficient OPG design resources available.	Delay project schedule and milestones	High	Design will be contracted out to an external agency. OPG Projects Design have committed to provide DTL support for this project.	Low
Availability of qualified vendors to perform engineering	Delay in issuing contract due to the need to assess various interfacing risks and vendor qualification issues and contracting language	Medium	Obtain OPEX from other OPG projects of similar nature. Early involvement with Supply Chain and various other departments on potential vendors and the associated contracting strategies.	Low
Technical				
Commercial drum cleaning equipment being recommended may be more complicated than anticipated when installed in a nuclear system.	Costs and schedule delays if extensive testing and re-engineering is required.	High	Potential design vendor will be informed that the equipment must be evaluated for suitability in the plant before equipment purchase and implementation.	Medium
Meeting seismic requirements	Increase cost to the project due to unknown civil upgrades to meet the seismic requirements	High	Seismic qualification considered as part of the conceptual study. Seismic qualification requirements to be included in Preliminary Design.	Low
Legacy issues on Design	Re-engineering may be required if there are legacy issues with the systems that the Project is modifying.	High	Completed preliminary system walkdown to identify potential legacy issues. Further detail reviews of documents and site scanning will be conducted to determine impacts at the Preliminary Engineering stage.	Medium
Regulatory				
Regulatory approvals (CNSC/TSSA) may require moer time than anticipated	Delay in project and potential cost impacts to the contract.	Medium	Identify required time allowance in project schedule. Incorporate approved time in contracting strategy. Review OPEX with	Low

			similar projects.	
Environmental				
Drum cleaning procedures may impact of MOE requirements.	The drum cleaning method is yet to be finalized at the Design Stage. The solvent used may impact of MOE requirements, requiring special treatment before disposal.	High	The most appropriate method of drum cleaning will be evaluated during the Preliminary Engineering phase. Perform testing at vendor site if necessary.	Low
Health & Safety				
N/A				
Investment				
Some of the cost assumptions in the base case are worst case scenarios based on engineering judgment.	NPV and IRR results may be less optimistic than calculated.	Medium	Stakeholder line management was involved in obtaining information from historical performances of the systems.	Medium
Inability to recover investment	Insufficient time to recover capital investment before stations' end of life.	Medium	The current NPV and IRR indicate a return of investment before stations' end of life.	Low
Early end of life of PNGS	Insufficient time to recover capital investment if end of life is earlier then currently forecast	Low	Using the current forecast of DNGS end of life date the current NPV and IRR indicate a positive return on investment before stations' end of life	Low

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
TBD in Next Release	TBD in Next Release TBD in Next Release	TBD in Next Release TBD in Next Release	

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

CNSC	Canadian Nuclear Safety Commission
D_2O	Heavy Water
Downgraded D2O	Heavy Water of an isotopic that is not suitable for use in the moderator or the primary heat transport system
ECs	Engineering Changes
EOL	End of Life
IXCU	Ion Exchange Clean Up
OP&P	Operating Policies and Principles
PHT	Primary Heat Transport
Reactor Grade D2O	Heavy Water of an isotopic that is suitable for use in the moderator or the primary heat transport system
S&I	Storage and Inventory
Sulzer-B Upgrader	High curie heavy water upgrader
TOC	Total Organic Carbon
TRF	Tritium Removal Facility
UPP-B Upgrader	Low curie heavy water upgrader

Appendix "B" Project Funding History

$ 000's Release Type	Month	Year	Previous Releases (incl contingency)	Cumulative Values						Later	Total
None											0
											0
											0
											0
											0
											0
											0
											0
LTD Spent											0

Comments:

The current total project estimate of $17.4M (including [redacted] contingency) is a conceptual quality estimate of +60%/-25% and has an estimated Available for Service Date in Q2 of 2010. Altus Helyar has independently verified this estimate and includes a contingency of [redacted] as recommended by OPG Finance. Given that this estimate is based on conceptual information, there is a risk that this estimate may escalate (refer to Section 6, Risk Table)

Project funding in the amount of $5.0M [redacted] is listed in the current approved Business Plan 2006 to 2010. There is $0 capital spending released to date for this project. The funding variance in the Business Plan will be corrected via PCRAF in 2007.

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:
OPG staff will provide project management and support role during design and implementation.
Material cost assumptions are based on using Class 3 tanks, hangers, piping and associated components and equipment.
Design and installation work will be contracted out.

Financial Assumptions:
Escalation rate on employee wages: 3%
Escalation rate on other expenses: Canada IPPI

Project / Station End of Life Assumptions:
As per memo J. Froats to D. Power, May 10, 2006, File No. NK30-01060 P, Pickering B Units 5,6 and 7 will have a End of Life of 2014 and 2016 for Unit 8.

See Attachment D for details of Expenses & Savings assumptions.

Energy Price / Production Assumptions
N/A

Operating Cost Assumptions
New operating costs are negligible.
External costs to upgrade D_2O is $15/kg
Cost to lease D_2O from AECL is $0.055/kg/day

Other Assumptions:
All work is within the secured area with incumbent restrictions.
OPG will procure all Nuclear Class and Pressure Boundary materials.

PNGS-A D2O Storage and Drum Cleaning Facility Project 13 - 49251

Developmental Release Business Case Summary NA44-BCS-38000-00001-R000

Attachment "A" **Project Cost Summary**

Choose One Choose One	LTD Prior Yr 2006	This Release 2007	This Release 2008	Future Release 2008	Future Release 2009	Future Release 2010		Later	Total
Project Management (OPG)		435		671	748	538			2,392
Engineering & Drafting (OPG)		304		558	425	447			1,734
Material	[redacted]								
Installation – PWU, BTU									
Contract - Design									
Contract - Installation									
Contract - Other									
Interest (Capital Project Only)									
Project Costs (excl contingency)									
General Contingency									
Specific Contingency									
Project Costs (incl contingency)	-	1,330	1,176	2,837	7,720	4,319	-	-	17,382
2006-2010 Business Plan	200	1,000		3,000	800	-			5,000
Variance to Business Plan	(200)	15	898	(834)	5,093	3,297	-	-	8,269
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
[redacted] (excl contingency)	[redacted]								
Total Release (incl contingency)	-	1,330	1,176	2,837	7,720	4,319	-	-	17,382
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	Zero to Minimal		Quality of Estimate	Conceptual + 60% to - 25%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	No	Phase 1 Actual Used	N/A
Similar Projects	N/A	Contracts in place	N/A	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2006-2010 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Jan 2007.

Reviewed By: NOV 21/06

Stephanie Tham
Project Manager
Date:

Approved By: [signature] for Peter Floyd 22 Nov 06

Peter Floyd
Eng & Mods Manager (Strat IV)
Date:

ProjectPNGS-A D2O Storage and Drum Cleaning Facility Pr Name 13 - 49251

Developmental Release Business Case Summary NA44-BCS-38000-00001-R000

Attachment "B" **Project Variance Analysis**

Capital	LTD Nov 2006	Choose One: Last BCS N/A N/A	Choose One: This BCS Nov 2006	Variance	Comments
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material	[redacted]				
Installation - PWU, BTU	[redacted]				
Contract - Design	[redacted]				
Contract - Installation	[redacted]				
Contract - Other	[redacted]				
	[redacted]				
Interest (Capital Project Only)	[redacted]				
Project Costs (excl contingency)	[redacted]				
General Contingency	[redacted]				
Specific Contingency	[redacted]				
Project Costs (incl contingency)	0	0	0	0	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	0	0	0	0	
Total Release (excl contingency)	0	0	0	0	

Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:
N/A

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
21	DEC	2006	Project Start Milestone (PSM)
23	DEC	2010	Project Complete Milestone (PCM)
02	JAN	2009	Budget Quality Estimate Approved (BEA)
04	JUN	2009	Full Release BCS Approved (FR1)
17	JUL	2009	Major Contract Awarded (MCA)
19	NOV	2007	Preliminary Design Complete (DES)
03	DEC	2007	Engineering Work Scope Identified (ESI)
05	NOV	2007	Regulatory Approval Obtained (RAO)
17	SEP	2008	DCP Approved - Drum Cleaning Facility (DCP)
16	OCT	2008	DCP Approved - IXCU (DCP)
17	SEP	2008	Final Design Complete Phase 1 (FD1)
11	AUG	2009	Start of Installation (SOI)
07	JAN	2010	AFS - Drum Cleaning Facility (AFS)

A Project Execution Plan (PEP) will be approved by Aug 2007

Comments:
Other Key milestones:

26	APR	2010	AFS- IXCU (AFS)
[illegible]1	JUL	2010	In-Service Declaration (ISD)
26	NOV	2007	Long Lead Materials Identified (LLT)

Attachement D: Incremental Costs & Expenses Assumptions

Category	Comments	
	Before PND-B End of Life (2007 to 2016)	After PND-B End of Life (2017 to 2026)
Expenses Without Drum Cleaning Facility (DCF)		
New Drum Purchases	[redacted]/drum x 20 drums/year, 0 drums/yr after AFS	15 drums/year after PB end of life; 0 drums/yr after AFS
Additional Drum Handling Cost	2.7 drums/day @ 3 hours/drum x [redacted] x 365d; 0 drums/yr after AFS	2.0 drums/day after PB end of life; 0 drums/yr after AFS
Costs to clean drum contents	[redacted] per event once every 2 years; $0 after AFS	
Costs on Drum Disposals	10 drums x 0.25 m3 x [redacted]/m3 disposal; $0 after AFS	7.5 drums after PB end of life ; $0after AFS
Leasing costs-D2O Makeup for unprocessable water	[redacted] x (0.3 drums/day x 365d/yr x 230 L/drum x 30% isotopic x 1 kg/L) x 200 days of lease; $0 after AFS	0.2 drums/day after PB end of life; $0 after AFS
Expenses Without Additional IXCU tanks		
Costs to cleaning IXCU Tanks	105K per event once every 2 years $0k after AFS	
·erator Work Around for ·k Handling	2 FTE; 0 FTE after AFS.	
Upgrader Degradation - External Mitigation Costs (with escalation)	External upgrading cost=[redacted] when demand feedrate is less than upgrader's capability; Without IXCU, entire yearly load will be upgraded externally during repacking in 2014. Upgrader degradation rate: -8Kg/hr/yr :UV in service only in 2007, or -2kg/hr/yr: UV & IXCU in service in 2010; Demand feedrate reduces from 150kg/h to 105kg/h in 2015/2016 when 3 PB's units are out of service.	Same except the Demand upgrader feedrate reduces to [redacted] after PB end of life.
Packing Change Costs (with escalation)	[redacted] to repack in 2014 without IXCU tanks; or delayed to 2042 if IXCU is installed.	
Expenses Without Additional S&I tanks		
Offsite water storage - TDO Shipments Costs	[redacted]/TDO trip x 7.5 trips/year; 0 trip after AFS	5 trips/year after PB end of life; 0 trip/year after AFS
Incremental Operating Expenses of DCF		
Operation Expense of DCF - Labour	1FTE	
Incremental Operational Expense - Utilities	[redacted]/drum x 10 drums/day x 365days	
·aste Disposal Costs of DCF	100 drums with sludge of 3.5" in each (ONE TIME COST of 0.0889m x (0.61m/2)^2*Pi) x [redacted]3.	

Attachement D: Incremental Costs & Expenses Assumptions (Cont..)

Category	Comments	
	Before PND-B End of Life (2007 to 2016)	After PND-B End of Life (2017 to 2026)
Savings After Additional S&I Tanks Installed		
Fuel Burn Up Savings	About 187Mg of the yrly TRF product shortfall can be received to detritiate & improve moderator isotope after AFS (reference: Kinectrics Report Appendix A for detailed calculation & yearly distribution).	
Dose (ALARA) Savings	About 187Mg of the yrly TRF product shortfall can be received to detritiate & improve ALARA after AFS (reference: Kinectrics Report Appendix A for detailed calculation & yearly distribution).	

CFC Chiller Replacement Project 13 - 40543

Full Release (Phase 2) Business Case Summary P-BCS-73000-00001-R002

1/ RECOMMENDATION:

We recommend a Phase II full release for a total of $22,377 K (including contingency) to complete the following:

- The installation/commissioning of the three Reactor Auxiliary Bay (RAB) Chillers,
- The detailed design and installation/commissioning of the three Service Wing (SW) Chillers
- The installation/commissioning of the Administration Building Extension (ABX) Chiller

The objective of this sustaining project is to replace the seven (7) existing Pickering CFC Chillers in order to:

- comply with the amendments by Environment Canada Federal Halocarbon Regulations-2003.
- remove some of the obstacles for returning the System Health status of each system from red/yellow to white, by addressing increasing maintenance on this aging equipment
- provide contingency planning to meet regulation requirements prohibiting major chiller repairs after January 1, 2005.

Failure to comply with this new regulation would result in significant fines, legal ramifications, and a significant impact to our corporate image.

A Phase I full release of $6.7M was previously approved in January of 2005. After progressing through the Phase I portion of the project, it was realized that the split of Phase I and Phase II work would need to be revised to accommodate a more cost effective installation sequence. Also during this project phase, it became apparent that both Phase I and overall project costs would be significantly higher than originally estimated. The estimated cost of work previously identified as Phase I is now $16.8M versus the previously released $6.7M. The overall project cost estimate is now $22.4M versus the previously estimated $9.4M due to discovery work, improved cost estimates after the completion of more detailed engineering, and receipt of more accurate vendor quotations.

The details of the cost increases and progress to date are outlined in the Background / Issues section of this BCS. SCR No. P-2006-18017 has been raised to document the problems with the estimate used for the Phase I BCS.

With most of the engineering complete, RAB platform and chillers in place, RAB installation experience gained, and a third party cost estimate review, we feel confident that this project can be finished on time and within the cost estimate of $22.4 M. The estimate includes a specific contingency of $1.7M and a general contingency of $1.4M for unforeseen issues.

$000's (Incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	Full - Phase 1	4,006	2,735						6,741
Requested Now	Full - Phase 2	(110)	932	8,843	5,127	844			15,636
Future Funding Req'd									-
Total Project Costs		3,896	3,667	8,843	5,127	844	-	-	22,377
Ongoing Costs									-
Other Costs									-
Grand Total		3,896	3,667	8,843	5,127	844	-	-	22,377

Investment Type	Class	NPV or IEV	IRR	Discounted Payback
Regulatory	Capital	(14,499)	N/A	N/A

Submitted By:

T. Mitchell
Site V.P. Pickering

Date: 7 NOV 2006

Finance Approval:

D. Power
Director of Investment & Business Planning

Date: Jan 11/07

Line Approval (Per OAR Element 1.1 Project in Budget):

J. Hankinson
President and CEO

Date: Feb 8/07

2/ BACKGROUND & ISSUES

Pickering "B" NGS has seven (7) CFC Chillers located in three separate areas that need replacement with non-CFC units (Reference: ECR 734369 and SCR P-2003-03155). This project will ensure that Ontario Power Generation (OPG) PNGS B complies with the Environment Canada amendments to the Federal Halocarbon Regulations 2003, and the potential changes on Provincial Legislation O/Reg 189. This regulation prohibits the re-charge of CFC refrigerant in any chiller unit by January 2015. Although OPG has made a commitment to the Ministry of Environment (MOE) to replace all their CFC chillers by 2012 (N-CORR-00521-00008), management has chosen a more aggressive deadline for completion by 2010.

Furthermore, should a chiller fail requiring the replacement or modification of an internal sealing device, internal mechanical part, or an evaporator or condenser tube, between January 1st, 2005 and December 31, 2009 that unit can be returned to service for up to one year, at which time it must be replaced with a chiller using an approved or non-ozone depleting refrigerant. Should a chiller fail catastrophically after January 1st, 2010, that unit must be replaced or charged with an approved refrigerant (non-ozone depleting) immediately prior to being brought back into service. The existing chillers are not suited to have their refrigerants changed to a non-CFC refrigerant. The only option is to replace the units.

The following activities were completed with Phase I funds:

- Preliminary engineering for the ABX, SW and RAB chillers is complete
- Detailed Engineering is complete for ABX and RAB chillers
- All RAB chillers have been delivered and installed on the newly erected chiller platform but not tied-in to the existing system
- The ABX chiller has been factory tested, accepted, and delivered to OPG
- SW chillers have also been factory tested and accepted and will be delivered in October of this year
- All pumps have been delivered to site
- Detailed engineering for the SW chillers is in progress.

Premature Chiller Failure Contingency Status:

- With the RAB Chillers installed with only the mechanical and electrical tie-ins outstanding, if an RAB Chiller failed and required replacement, the tie-ins could be completed within the 1 year grace period.
- Should the ABX Chiller fail, a TMOD would be prepared to tie in to the Admin Building chilled water system within the one year grace period. This TMOD would mimic a similar one that was successfully used in the past.
- 90% of the SW Chiller design is complete and if a SW Chiller suffered a catastrophic failure, with a change in installation schedule, a SW Chiller could be replaced within the one year grace period.

Extra expenditures that were incurred during Phase I of the project are as follows:

- Increased labor costs and firm quotes from potential vendors for installation were higher than originally estimated.
- Chiller vendor delays in submitting equipment documentation for approval resulting in less efficient use of design engineering hours.
- Poor quality of vendor documentation resulting in extensive document reviews and comments with multiple iterations back and forth prior to obtaining final approval.
- Electrical redesign to accommodate power supply constraints. Design changed from a 600V supply to using a 4kV supply which necessitated the specification and use of step down transformers and current transformers.
- Discovery work for the RAB chiller design due to the realization that a structural column (M139) was discovered to have insufficient capacity to support the weight of the new air-cooled RAB chillers. This column had to be reinforced prior to both completion of the platform and installation of the chillers

The Phase II funds will ensure that the following activities of the project are completed:

- Installation of the mechanical and the electrical components of the RAB chillers; Commissioning and Available for Service Declaration,
- Full installation of the ABX and SW chillers, commissioning and Available for Service Declaration, and
- Close-out activities for the project.

The project schedule has been revised to reflect the current installation strategy and the previously encountered delays. The installation schedule is affected by both operational and weather constraints. For example, all outdoor work cannot be performed during the winter months. The adopted schedule for the recommended alternative takes these constraints into account while minimizing the overall project duration.

The release strategies considered were:

(a) Prepare a superseding Phase I BCS documenting the change in cost of the original Phase I scope of work and request a release for $16.9M. Then follow with a Phase II BCS requesting a release of $22.9M to complete the project.

(b) Superseding Phase 1A BCS requesting a release of $19.8M to complete the revised scope of work included in Phase 1A (Includes the installation of the ABX Chiller, two SW Chillers, and two RAB Chillers). Then follow with a Phase II BCS requesting a release of $22.4M to complete the project.

(c) Proceed directly with a Phase II release of $22.4M based on the new installation strategy, while documenting both the progress and issues associated with the original Phase I release.

Option (a) was not selected as it is a more costly option. Option (c) is preferable to option (b) as the relative increment in the amount released is low, there is adequate information to reasonably estimate the full project cost, and the project schedule now requires a full release in October 2006 to commit to the installation contract.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Do Nothing	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay (2yrs)	Alt 3 Ph. I Install Schedule	Alt 4 Do Less	Alt 5 Do More	Alt 5
Project Cost	N/A	(11,126)	(5,926)	(11,759)	N/A	N/A	N/A	N/A
NPV (after tax)	(14,499)	(15,011)	(10,758)	(13,803)	N/A	N/A	N/A	N/A
Impact on Economic Value	N/A	N/A	(7,934)	N/A	N/A	N/A	N/A	N/A
IRR%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Discounted Payback (Yrs)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Note: The figures shown above are for the RAB Chiller portion of the project only. As outlined below, the Service Wing and ABX Chillers must be replaced to meet the 2015 environmental regulation implementation date since they are common to Pickering B and A and will therefore be required to operate after the 2014 Pick B end of life date. The justification for proceeding with the RAB Chiller replacement is based on a financial analysis since it only services Pickering B and could feasibly be delayed until after a decision is made for Pick B plant life extension. The financial justification is made by comparison of the incremental NPV's for the different alternatives strictly for the RAB portion of the project.

Stop the Project - Not Recommended

Consequences of doing nothing are increased chances of encountering chiller failures as they are approximately 5 years beyond their life expectancy and experiencing condenser tube erosion. Details of the probabilities of failures, consequences of failures, and current status of the various chillers are outlined in attachment "E". A summary of the consequences of failure are described below:

Failure of the ABX Chiller: Results in a loss of cooling to the Administration building where Pick A / B support staff, CNSC and TSSA staff are located. The 2014 end of life for Pickering B does not apply in this situation as Pickering A staff are also located in the Admin. Building and the chiller would have to be replaced by 2015.

Failure of two Service Wing Chillers: Results in a loss of cooling to the chemistry lab which provides critical services to both Pick A and B which can affect station operability and guarantees of shutdown during an outage. Again, the 2014 end of life date for Pick B does not apply as this affects Pick A as well and must be replaced by 2015 as required by the environmental regulation.

Failure of two RAB Chillers: Results in a loss of cooling to the Main Control Room and Control Equipment Room where a temperature controlled environment must be maintained at all times. A loss of cooling to these areas could potentially result in a four unit shutdown. These chillers do not affect Pick A and therefore the 2014 end of life date does apply. The probability of a dual unit failure of the RAB Chillers is estimated at 50% between now and 2015. However, based on the NPV calculated for the RAB portion of the project, with a low probability of revenue losses due to a four unit shutdown, it is a more costly option than the recommended option. The NPV for this alternative is **NPV = (14,449)**.

Alternative 1 - Continue project per Phase II schedule - Recommended

The ABX and Service Wing chillers should be continued as per the revised Phase II schedule (see attachment "C") since they service Pick A and will need to be replaced by 2015 as mandated by the environmental regulations. The Pick B end of life 2014 does not apply to these chillers.

For the RAB Chillers, the financial analysis show that this is the most cost effective approach given the risk of a four unit shutdown and the subsequent revenue losses. The **NPV = (10,758)** for this alternative.

Successful completion of this project will fulfill environmental regulations and improve the current red/yellow status of each associated HVAC system health indicator.

Alternative 2 - Delay Project - Not Recommended
The schedule can be delayed by as much as two years, and still meet the MOE commitment to replace all CFC chillers by 2012. This, however, would pose a significant threat to the station as the one year 'grace' period to replace failed CFC chillers, will be eliminated after January 1, 2010.

This option is not recommended for the ABX or Service Wing Chillers because the cost savings due to time value of money is relatively insignificant (approx. $100K) and the project team is already mobilized to continue per the recommended schedule, and resources have already been committed based on this schedule.

The option of delaying by two years is not recommended for the RAB Chillers because the financial analysis shows this to be a more costly option than the recommended alternative. This is primarily due to the increased probability of a two unit RAB chiller failure potentially causing a four unit shutdown resulting in revenue losses, as well as additional de-mobilization / re-mobilization costs. The **NPV = (13,803)** for this alternative.

Alternative 3 – Proceed with installation as per Phase I release schedule - Not Recommended

This alternative is no longer viable because this schedule change only affected the installation of the ABX Chiller and has no impact on the costs of the RAB portion of the project. However, had this schedule been used, additional overall project costs of approximately $800 K would have been incurred.

Alternative 4 – Do Less - Not Recommended

All seven CFC chillers are impacted by the environmental regulations; doing less will lead to non-compliance and un-reliable performance of the system. The technical requirements of the recommended option (Alternate 1) are acceptable. Additionally, the costs of the recommended option have been minimized through on-going review and challenge.
A comparison of this project to the Darlington CFC Chiller Replacement project shows that the two projects are very different, where the Darlington installation is a plug and play approach; Pickering's installation involves the relocation of the RAB and ABX chillers to the outside and the redesign of the Service Wing chillers. In addition, the QA requirements for the new chillers at Pickering were more stringent at the time of purchasing which resulted in more expensive design and equipment costs. Although using air cooled chiller designs for RAB and ABX chillers, increased costs, they benefited the station by reducing the already limited service water supply. The need to evacuate control room staff in the even of a refrigerant leak would also be eliminated by the relocation of the RAB chillers to the roof.

Increased costs due to replacement of the glycol pumps, design of a chiller platform, increased piping and piping design changes, the need for new power supplies, were incurred as a result of relocating the RAB Chillers to the outside. Based on current estimates, the 'per ton' cost of the Darlington CFC Chiller Replacement project comes to approximately $10.4K/ton compared to this project which comes to approximately $20.8K/ton.

Alternative 5 – Do More - Not Recommended

The current scope of the project has effectively addressed the potential modification requirements. Adding scope at this stage would increase costs without making a meaningful contribution to the overall project objectives.

4/ THE PROPOSAL

We recommend the completion of this project by the end of 2009. The key project milestones are shown in the table below:

Completion Date			Description
Day	Mth	Yr	
22	Dec	2006	Complete DCP package for Service Wing chillers
21	Nov	2006	Start installation for all RAB chillers
21	Feb	2007	AFS of RAB chilled-glycol pumps and Relief Valve RV102
23	Feb	2007	Start tie-in installation for 1st RAB chiller (058-73180-RFU4)
01	Nov	2007	Start tie-in installation for 2nd RAB chiller (058-73180-RFU5)
01	Nov	2008	Start tie-in installation for 3rd RAB chiller (058-73180-RFU6
01	Aug	2007	Start Installation and tie-in for ABX chiller
03	Aug	2007	Start Installation and tie-in for 1st SW chiller (018-73430-RFU2521)
01	Feb	2008	Start installation and tie-in for 2nd SW chiller (018-73430-RFU2522)
02	July	2008	Start installation and tie-in for 3rd SW chiller (018-73430-RFU2520)
02	July	2007	AFS 1st RAB chiller
03	July	2008	AFS 2nd RAB chiller
02	July	2009	AFS 3rd RAB chiller
03	July	2008	AFS ABX chiller
14	Dec	2007	AFS 1st SW chiller
19	June	2008	AFS 2nd SW chiller
18	Nov	2008	AFS 3rd SW chiller
24	Dec	2009	Project Completion

5/ QUALITATIVE FACTORS

The following are the non-quantifiable benefits of the project. The major project measurable deliverables are listed in Section 4.

- Improve reliability of the chiller units in each area; hence reduce emergent-based maintenance costs.
- Improve safety by eliminating hazards due to refrigerant leaks in an enclosed space for the Reactor Auxiliary Bay and Administration Building (Air-cooled units are installed outdoors)
- Alleviate strain on Low Pressure Service Water (Safety-Related Support System) by replacing the Reactor Auxiliary Bay and Administration Building chillers with outdoor air-cooled units.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Detailed release estimates for the installation of SW Wing Chillers is unavailable during BCS phase II preparation.	Complete installation costs are not available in the cost esitmate. Therefore, project may over spend estimated budget	**High**	Include 30% contingency for the installation of the Service Wing Chillers. Apply only 15% contingency on the RAB and ABX chillers. See Attachment "A" for Service Wing contingency. Independent 3rd party review of the cost estimate for the Phase II BCS was conducted by Helyar.	**Low**
Further cost estimation on the total project	Cost push on the $22.4M total	**Medium**	Vendor quotes are now available for all aspects of the project except for the SW chiller installation. 90% of Detailed Engineering is complete for the SW Chillers Design Package. A third party review estimate has been completed and incorporated into this estimate A higher (30%) contingency was used to reflect the higher uncertainty for the installation of the SW Chillers.	**Low**
Scope				
Discovery and Legacy Work (chiller system is 20 years old - Auxiliary equipment failure)	Increase in costs and impact on schedule	**High**	COMs Meeting and Walkdown were performed to minimize discovery work. Reviewed equipment history and are continuing to perform preventative maintenance on any support systems during modification. Initial documentation check was conducted. Pre-identifying documentation errors. Field Engineering involved early in the design phase. Multiple field walkdowns were done to determine scope of legacy issues. Any increased	**Low**

			design scope would be covered by general contingency funds.	
Schedule				
Premature Chiller failure, schedule may vary due to station priorities (contingency plan - failure equipment trigger 1 year replacement).	Negative impact to Cost, Scope and Schedule.	**High**	RAB: At time of Phase II release, all three existing chillers are functioning. New chiller units are installed at this time. Complete installation (i.e. piping, electrical cable, instrumentation) can be accomplished within 1 year. Risk is Low. ABX: Develop TMOD to tie into the Administration Building chilled water system to Administration Building Extension system. Risk is Low SW: If a SW chiller fails during the life of the project and needs to be replaced, the installation schedule can be re-prioritized to allow for the installation of the replacement SW chiller ahead of other chiller installations. The cost associated with implementing these contingency plans is estimated to be $300K	**Low**
Contractor/OPG managed task delays	Schedule delay and negative cost impact	**High**	Review detail installation and commissioning strategies. Ensure Contract Administrator and Monitor scrutinize daily activites of Contractor. Resources to immediately respond when problems are encountered in the field. Order materials proactively; that is, ahead of scheduled activity per 13-week IOP schedule. Extra costs associated with this risk are covered under general contingency.	**Low**
Other modification projects i.e. Cafeteria Upgrades) occuring in the same location ABX, RAB and SW chillers at	Delay to schedule due to conflicting work activities in the field.	**High**	Communicate with Contract Management office continuously during modification. Coordinate with other project teams to avoid and mitigate any conflicts	**Low**

the same time.			Rescheduled ABX Chiller Installation from November 1, 2006 to August 1, 2007 to accommodate the Cafeteria Upgrades project.	
Resources				
Availability of Qualified OPG station staff during outage and non-outage periods	Fewer resources to complete tasks. Increased risk in schedule delays. Outage organization requires full support from Installation support staff	**Medium**	Early involvement of operation and maintenance support. Ensure compliance of IOP work planning & station support. Defer any non-critical activities to accommodate station resources. Commitment obtained from outage organization to supply limited staff for installation activities during outage periods.	**Low**
BTU staff may not be available to perform RAB chillers RFU5 and RFU6 Tie-in activities; Project may be required to use External Contractor Resources	Increase cost to use external contractor.	**Medium**	Include specific contigency to cover additional costs if BTU staff cannot be commited to this activity. The cost estimate for this is $200K	**Low**
Lack of available qualified contractors to execute the installation	Schedule delays and cost push	**Medium**	The request for proposal to the installation contractors will be issued immediately after the approval of this BCS to meet the schedule. Contractors have already been briefed on the scope and schedule for this work. Standard skilled trades will be used for this installation. Specialized commissioning services will be provided by the Chiller equipment vendor.	**Low**
Technical				
Unforeseen commissioning issues with chiller units	Delay in schedule	**Medium**	Chiller vendor field representatives will be on-site for startup/commissioning. Also, project team will be on standby to resolve any issues	**Low**
Regulatory				
A project delay or cancellation would result in a failure to comply with the new environmental regulation.	The corporation could face significant fines and there could be legal ramifications. This would also have a potentially serious impact on the corporate image.	**Medium**	Securing funding to implement installation and commissioning activities will ensure that OPG remains compliant with the environmental regulation. The management expectation for completion of this project is 5 years ahead of the environmental regulation	**Low**

			implementation date.	
Environmental				
Unforseen chemical handling procedures during this work	Higher Cost. Approximately $50K worth in additional chemical handling charges	**Medium**	Ensure refrigerant and materials (lubrication) brought on site are concurred by Environmental group. Extra costs are included in specific contingency.	**Low**
R-11 (CFC) refrigerant disposal more effort intensive than anticipated	Higher Cost. Approxmately $50K worth in additional chemical handling charges	**Medium**	Early involvement with Disposal companies. Meetings with this vendor show that there is no cost to remove R-11 refrigerant. Potential extra costs are included in specific contingency.	**Low**
Health & Safety				
Workplace injury or serious MRPH event	Negative impact to Schedule due to delay for investigation.	**Medium**	Work plans will be reviewed by conventional safety prior to use. JSA to be prepared for crane/rigging and high hazard work. Lessons learned applied to prevent further incidence. Comprehensive work skill OPEX review.	**Low**
Investment				
New chillers operation, reliability and service-life below expectation	More maintenance and operational related activites	**Medium**	Technology of the new Chillers is standard and is widely used in industry. They are manufactured by Trane, one of the world's leaders in HVAC equipment. Chillers are factory acceptance tested and inspected by OPG Source Inspector prior to delivery.	**Low**
Newly purchased chillers become obsolete through the life of the project.	Unable to purchase spare-parts; no service support from the vendor	**Medium**	Technology of chillers changes slowly compared to the life of the project. Purchase spare-parts as part of the equipment purchase orders.	**Low**
New regulatory requirements which change the acceptable replacement refrigerants	Cost and schedule delay to re-engineer the chillers for a new refrigerant	**Medium**	The selected refrigerants are not only acceptable for use post 2015 but they are also not on the list of refrigerants to be phased out by 2030. Therefore there is a minimum of a 24 year expectancy.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jul 2009	Jul 2010	Director of Station Engineering (Pickering A and B)

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Design meets performance reliability criteria	Chillers meet system requirements using CFC refrigerant.	Replacement chillers to operate within design parameters using non-CFC refrigerant	Commissioning reports will document performance parameters	Projects
2.	Design meets performance reliability criteria	Not Applicable	AFS procedure to be performed and accepted	Final acceptance of AFS during final meeting.	Stakeholders
3.	Removal of ozone depleting substance	Not Applicable	All ozone depleting substances pertaining to this project to be removed	Projects to ensure that all ozone depleting substances are removed from site.	Site Management Board
4.	Improve health status of chillers	System health reports shows RAB and SW chillers are yellow. No status is available for ABX	System health of chillers will be improved to white/green.	Compare system health reports from project initiation to project completion	Performance Engineering
5.					

Appendix "A" **Glossary** (acronyms, codes, technical terms)

RAB – Reactor Auxiliary Bay

ABX – Administration Building Extension

SW – Service Wing

Free Cooling - HVAC systems rely on outside air for cooling (outside air temperature is below 12C); air is directly drawn into the building. Chillers and systems are turned off.

Cooling season – Time when chillers are operating.

Heat Load – "Heat" in the building.

Appendix "C" — Financial Model – Assumptions

Project Cost Assumptions:

Project Resources (e.g. Projects Design, Drafting office, Maintenance, etc.) provided estimates on monetary resources required to complete their work activities for the duration of 2006 to the end of project. Overtime is anticipated for Projects, Field Engineering and Maintenance resources. Allowances have been incorporated into the project cost.

Installation costs (including materials and installation contractor) for the RAB and ABX chillers are of release quality (+10 to -15%). Installation costs for Service Wing chillers are budgetary (+30 to -15%) since detailed engineering is not complete at the time of BCS issuance.

Project cost estimates have been verified by an independent third party review.

Financial Assumptions:

An interest rate of 6% per annum, labor escalation rate of 3% per annum and an NPV discount rate of 7% are used per corporate standards.

The following assumptions were used to calculate revenue losses due to a forced outage:

- Rates per MW hour:

2007	2008	2009	2010	2011	2012	2013	2014	2015
\$55.3	\$56.2	\$54.1	\$51.8	\$49.6	\$48.4	\$49.3	\$51.7	\$54.2

- Probability of a two unit RAB Chiller failure between now and 2015 is estimated to be 50%. Spread uniformly over 9 years is approximately 5.6% per year
- Output from each unit is 516 MW
- Failure of two RAB chillers would result in a loss of cooling in the Main Control Room / Control Equipment Room servicing all four Pickering B units and would cause a four unit shutdown
- Optimistic duration for an overhaul or replacement is 4 weeks. Therefore the assumed duration of the forced outage is 28 days.

Project / Station End of Life Assumptions:

All Obsolete chillers do not have salvage value; the RAB and ABX chillers are isolated and abandoned in place during construction. Old SW chillers are replaced with new chillers. There is no salvage value assumed for the SW chillers.

Pickering B end of life is 2014. The SW and ABX Chillers also service Pickering A. The RAB Chillers service Pickering B only.

Energy Price / Production Assumptions

N/A in NPV calculations

Operating Cost Assumptions

N/A in NPV calculations

Other Assumptions:

No other assumptions

CFC Chiller Replacement Project 13 - 40543

Full Release (Phase 2) Business Case Summary P-BCS-73000-00001-R002

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2005	This Release 2006	This Release 2007	This Release 2008	This Release 2009			Later	Total
Project Management (OPG)	233	213	295	139	108				**988**
Engineering & Drafting (OPG)	1,477	989	860	811	210				**4,347**
Material	776	74	1,149	794					**2,793**
Installation – PWU, BTU	10	166	242	169	75				**662**
Contract - Design	406	27	30						**463**
Contract - Installation	600	1,341	3,808	1,173					**6,922**
Contract - Other	52	35							**87**
Installation - Support	234	265	635	323	17				**1,475**
									-
Interest (Capital Project Only)	108	262	442	380	50				**1,242**
Project Costs (excl contingency)	**3,896**	**3,372**	**7,461**	**3,789**	**461**	**-**	**-**	**-**	**18,979**
General Contingency		242	847	254	74				**1,417**
Specific Contingency		22	536	1,043	109				**1,710**
Project Costs (incl contingency)	**3,896**	**3,636**	**8,843**	**5,086**	**644**	**-**	**-**	**-**	**22,105**
2006-2010 Business Plan	3,896	2,771	1,190	590	291				**8,738**
Variance to Business Plan	**-**	**601**	**6,271**	**3,498**	**#REF!**	**-**	**-**	**-**	**10,241**
Committed Cost									**-**
Inventory Write Off Required					200				**200**
Spare Parts / Inventory		31		41					**72**
Total Release (excl contingency)	**3,896**	**3,403**	**7,461**	**3,830**	**661**	**-**	**-**	**-**	**19,251**
Total Release (incl contingency)	**3,896**	**3,667**	**8,843**	**5,127**	**844**	**-**	**-**	**-**	**22,377**

Ongoing OM&A (non-project)	**N/A**								**-**
Removal Costs (incl in above)	**N/A**								**-**

Basis of Estimate					
Design Complete	90 to 100%	Contracts in place	No	Competitive Bid	Yes
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Sponsor Cost Estimate	Yes	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in Place	No	Competitive Bid	Yes

Variance to Business Plan

The estimated variance to the 2006 – 2010 Business Plan will be addressed through the portfolio management process. A PCRAF was approved in Jul 2006.
Note: General contingency for the SW chillers (approx. $1.1M) is included in the value for overall project specific contingency.

Reviewed By:

Name
Project Manager

Date: 23 Oct, 2006

Approved By:

Name
Eng & Mods Manager (Strat IV)

Date: 23 Oct/06

CFC Chiller Replacement Project 13 - 40543

Full Release (Phase 2) Business Case Summary P-BCS-73000-00001-R002

Attachment "B" Project Variance Analysis

Capital	LTD Aug 2006	Phase 1 Release Last BCS Dec 2009	Phase 1 Release This BCS Dec 2009	Variance	Comments
Project Management (OPG)	317	598	988	390	See Note 1 [Estimate]
Engineering & Drafting (OPG)	2232	2330	4347	2017	**See Note 2** [Delay, Discovery, Re-Eng]
Material	785	1759	2793	1034	**See Note 3** [Discovery, Estimate]
Installation – PWU, BTU	12	125	661	536	See Note 4 [Estimate]
Contract - Design	428	200	463	263	See Note 5 [Estimate, Discovery]
Contract - Installation	1175	2781	6922	4141	**See Note 6** [Estimate, Discovery]
Contract - Other	71	20	87	67	See Note 7 [Estimate]
Installation support	371	386	1475	1089	**See Note 8** [Estimate]
				0	
Interest (Capital Project Only)	295	604	1242	638	
Project Costs (excl contingency)	**5686**	**8803**	**18978**	**10175**	
General Contingency		**598**	**1417**	819	See Note 9 [Estimate]
Specific Contingency			1710	1710	See Note 9 [Estimate]
Project Costs (incl contingency)	**5686**	**9401**	**22105**	**12704**	
Committed Cost				0	
Inventory Write Off Required			200	200	See Note 10 [Estimate]
Spare Parts / Inventory			72	72	See Note 10 [Estimate]
Total Release (incl contingency)	**5686**	**9401**	**22377**	**12976**	
Total Release (excl contingency)	**5686**	**8803**	**19250**	**10447**	

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

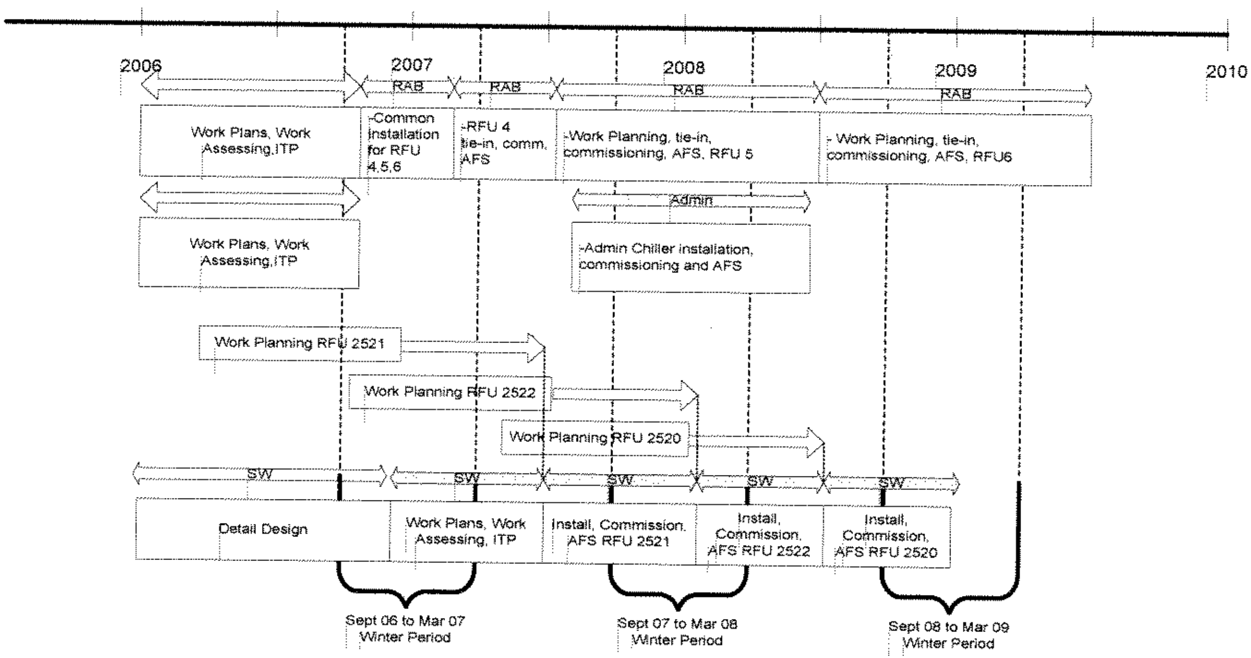
Note 1 – Variance is due to adjustments from conceptual estimates to quality-release/budgetary estimates.
Note 2 - Increase in Engineering costs are due to: delay in design deliverables - Design Engineering ($640K), discovery work – Design Engineering ($94K), additional project engineering ($350K total; $230K worth in delays and $120K worth in discovery work/scope creep), and adjustments from conceptual estimates to quality-release/budgetary estimates ($933K).
Note 3 – Increase in Materials costs are due to re-engineering, discovery work ($286K) and adjustments from conceptual estimates to quality-release/budgetary estimates ($748K).
Note 4 - Variance is due to adjustments from conceptual estimates to quality-release/budgetary estimates.
Note 5 - Variance is due to adjustments from conceptual estimates to quality-release/budgetary estimates. This variance includes impact of discovery work to reinforce column M139 and the change from the conceptual RAB platform design.
Note 6 - Original estimate was based on conceptual design and direct-hire labor rates of 2004; this new estimate is based on 100% detailed engineering for the RAB and ABX chillers, and 60% engineering complete for the Service Wing chillers and higher labour rates. In addition, installation hours have increased for this estimate. The variance due to increased labour-rates is $880K. The variance due to increased labor hours is $3261K
Note 7 - Variance is due to adjustments from conceptual estimates to quality-release/budgetary estimates.
Note 8 – Increase to Installation Support costs are due to emergence of a new project resource, Contract Management Office ($332K). Their cost is included in this release. In addition, Field Engineering Costs have also increased for this release ($757K).
Note 9 - 15% contingency is applied to the Reactor Auxiliary Bay and Administration Building portions of the project. 30% contingency is applied to the Service Wing portion of the project. Itemized contingencies (as specified in Section 6) are included in the Specific Contingency.
Note 10 – Inventory Write-off/Spare-part inventory costs were not included in the previous estimate.

Summary of major issues	Total Cost (K)
Underestimation - Conceptual Estimate to Quality/Budgetary estimate, including interest	$7925
Delay in Schedule due to delay in Design deliverables	$870
Discovery Work, Re-engineering	$500
Labour rates based on 2004 for phase I vs. new rates of 2006 for Phase II	$880
Inventory write off and spare parts / inventory costs	$272
General Contingency	$819
Specific Contingency	$1710
Total	$12976

Attachment "C"

Chiller Replacement Schedule
Business Case Summary Phase II Release

Friday, September 15, 2006



**In-Service Schedule: ABX - June 2007, SW RFU 2521 - Jan 2008, SW RFU2522 - June 2008, SW RFU 2520-Nov 2008
RAB RFU 4 - June 2007, RAB RFU5 - May 2008, RAB RFU6 - May 2009

Attachment "D"

REIS Declaration Milestones		
AFS Milestone	Declare REIS date	% complete
RAB Structural Steel Platform	30 July 2006	10%
RV102, P1 & P2 Partial AFS	16 March 2007	3%
RAB RFU4 – AFS meeting	01 August 2007	13%
RAB RFU5 – AFS meeting	01 August 2008	13%
RAB RFU6 – AFS meeting	01 August 2009	13%
ABX RFU101 – AFS meeting	01 August 2008	15%
Service Wing RFU2521 – AFS meeting	18 January 2008	11%
Service Wing RFU2522 – AFS meeting	13 July 2008	11%
Service Wing RFU2520 – AFS meeting	19 December 2008	11%
	Total	**100%**

Attachment "E"

	Number of Chillers	Status of Existing Chillers	Status of New Chillers	Probability of failure between now and 2010 (with 1 yr grace period for replacement)	Probability of failure between 2010 and 2015 (no grace period)	Consequence of Failure	Cost Status
RAB Chillers	3 X 50% chillers (i.e. two available during cooling season, 4-6 wks during peak of summer)	- All (3) are operational - All are approx. 5 yrs. beyond life expectancy	Bought and placed on platform, mechanical and electrical tie ins outstanding	1 Unit Failure: High, based on OPEX from SW Chillers and Pick A Chillers (PA Chillers were re-tubed over 10 yrs ago)	1 Unit Failure: Very High, based on OPEX and continued aging	1 Unit Failure: Loss of redundancy	- Approx. cost to complete is $5.9M (excl. contingency) - Approx. sunk cost is $5.2M - NPV reduction with a 5 yr delay is approx. $113 K
				2 Unit Failure: Medium-Low, based on OPEX and the potential for a common mode failure (i.e. tube erosion)	2 Unit Failure: Medium-High, based on OPEX and continued aging	2 Unit Failure: MCR / CER Temperature rise (> approx. 24- 26 deg. C) resulting in a multiple unit forced shutdown (approx. average time at risk for repair is 4 weeks prior to 2010 and longer for replacement if after 2010)	
ABX Chiller	1 X 100% chiller	- Operational - It is approx. 5 yrs beyond life expectancy	Bought and on site, but not yet installed	High, based on OPEX and common mode failure (i.e. tube erosion)	Very High, based on OPEX and continued aging	Loss of cooling to the new Admin Building resulting in discomfort to CNSC, and Pick A / B station support staff, and potential human performance issues There is a TMOD that can be used for to provide temporary partial cooling relief.	Approx. cost to complete is $2.3M (excl. contingency) Approx. sunk cost is $397 K NPV reduction with a 5 yr delay is approx. $44K, the cost of implementing a TMOD in the event of a failure is $300 K

Attachment "E" continued

	Number of Chillers	Status of Existing Chillers	Status of New Chillers	Probability of failure between now and 2010 (with 1 yr grace period for replacement)	Probability of failure between 2010 and 2015 (no grace period)	Consequence of Failure	Cost Status
Service Wing Chillers	3 X 50% chillers (i.e. two available during cooling season, 4-6 wks during peak of summer)	- 1 failed beyond repair, due to condenser tube erosion - Remaining 2 units have 60% tube erosion - All are approx. 5 yrs beyond life expectancy	Bought and on site, but not yet installed	1 Unit Failure: 100% (1 unit has already failed)	1 Unit Failure: 100% (1 unit has already failed)	1 Unit Failure: Loss of redundancy	Approx. cost to complete $4.7M (excl. contingency) Approx. sunk cost is $389 K NPV reduction with a 5 yr delay is approx. $88K
				2 Unit Failure: High, based on OPEX, significant tube erosion, and the fact that one has already failed	2 Unit Failure: Very High, Based on OPEX, continued aging, tube erosion, and the fact that one has already failed	2 Unit Failure: - Loss of cooling to the chemistry lab resulting in inaccurate sampling analysis and the inability to confirm analysis results (when temp increases to beyond 28 deg. C) which are critical to meet operating license requirements, MISA requirements, and station operability requirements. The lab is common to both Pick A and B and is therefore needed to sustain operability of Pickering B to its end of life as well as Pick A thereafter. Some examples include the measurement of Gadolinium levels in the moderator during shutdown every 4 hours per the operating license, which cannot be done off site. Other examples include deuterium levels in cover gas for various systems including the moderator, Heat Transport Storage Tank, Liquid Zone Control System, etc. where if action level 3 limits are reached the station must shutdown unless a downward trend is confirmed. Sampling of boiler ions is another example where if an action level 3 limit is reached, and the chemistry lab cannot produce quality analyses, shutdown would initiate after 4 hours. These cannot be shipped for sampling offsite. (approx. average time at risk for repair is 4 weeks prior to 2010 and longer for replacement if after 2010) - Loss of cooling to maintenance facilities resulting in discomfort and potential human performance issues for Pick A and B maintenance, ops, and stores staff	

Auxiliary Power System 13 - 49104

Full Release Business Case Summary P-BCS-50000-00004-R000

1/ RECOMMENDATION:

We recommend the release of an additional $50.2M (total $116.7M, including $17M contingency) to complete all activities for the design, build and commissioning of an Auxiliary Power System (APS) Project at Pickering NGS, to be in-service by the 3rd quarter of 2007.

On August 14, 2003 Pickering NGS suffered a site wide loss of Class IV power as a consequence of a Loss of Bulk Electrical System (LOBES) event. As a result, Pickering NGS was unable to operate a High Pressure Emergency Coolant Injection pump for approximately 5 hours, until power was restored from the grid. In addition, all of the operating units tripped and subsequently could not be cooled down without significant economic penalty until power to the station was restored.

The business objective of this project is to restore PNGS within it's licensing basis by enhancing standby power to:
- Be available to start an HPECI pump within 30 minutes of a LOBES event with no surviving units, and,
- Cooldown all 6 reactors to <90C within 24 hours of a LOBES event with no surviving units.

The above are the minimal regulatory requirements of the APS. The business objective will be met by providing a cost effective and reliable combustion turbine power generation facility that will provide back-up power to specific Pickering NGS loads following a LOBES event, should no units survive the transient.

Partial Release for $66.5M has been approved to commit to purchase of the combustion turbine units, and progress engineering on schedule-critical items so as to maintain viability of the September 2007 in-service date. As part of this partial release the station tie-in point has been reviewed and a cost/schedule savings can be realized by changing the station tie-in from the middle of the Station Electrical System (SES) bus to the end of the SES bus at U8. Changing the station tie-in point also changes the risks associated with the project. For the most part many of the IPB (inside plant boundary) risks are reduced or eliminated. Obtaining CNCS concurrence for sequencing of load profile may be required (see Section 6/ Risks). Attachment B outlines the savings realized by the station tie-in change.

This project is part of the 2005 - 2009 business plan for $200M. The 2006 Business Plan will be updated to reflect the cost estimates included in this BCS. The Project Execution Plan (PEP) was approved Nov7, 2005.

$ Millions Capital	$M Capital	Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Partial	66.5	66.2	Nov-05	Spent Life to Date:	3.3
Requested Now:	Full	50.2	33.5	2005-2009	Appr'd Business Plan (Tot Proj):	200.0
Cumulative Release:	Total to Date	116.7	99.7	2005-2009	Business Plan Variance:	(100.3)
Total Project Estimate:	+30% to -15%	116.7	99.7	2005	Budget (Current Year)	16.6
Current Year Estimate:	2005	16.6	16.6	2005	Budget Variance (Current Yr)	0.0
Type of Investment:	Regulatory	N/A	N/A	Cumulative Release Remaining:		33.5
NPV:			N/A	Contingency on Remaining Release:		16.7
IRR:			N/A	Contingency % on Remaining Release:		49.9%

Submitted By:

T Mitchell 02/10/2005

Tom Mitchell
Senior Site VP, Pickering B
Date:

Submitted By:

Nov 22, 2005

John Coleby
Senior Site VP, Pickering A
Date:

Finance Approval:

Don Power
Director, Investment & Business Planning
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Jim Hankinson
President and CEO
Date:

2/ BACKGROUND & ISSUES

On August 14th, 2003, Pickering NGS experienced a LOBES for approximately 5 hours. None of the three units operating at Pickering B survived the event. This led to a total loss of Class IV power across the two stations (Pickering A and B) and the Site Electrical System (SES) being unavailable.

Prior to the LOBES event, two key assumptions in the Design Basis for the station were;

1. 50% chance an operating unit will survive a load rejection and be available to energize SES, and,
2. The maximum duration of a LOBES would be less than one hour.

The August 14th event demonstrated that these design basis assumptions were not met. The major impact on PNGS was that High Pressure Emergency Coolant Injection (HPECI) was unavailable for approximately 5 hours and that the PNGS-B reactors could not be cooled down without substantial economic penalty, until the Bulk Electrical System was restored. Additionally, had the LOBES exceeded 8.5 hours, HPECI would have failed to meet its 1 x 10^{-3} unavailability limit. Given that there is no evident practical way to limit a grid collapse duration and the probability of such an occurrence cannot be demonstrated to be incredible, steps must be taken to restore the plant's design basis. The main objective of the project is to fully restore the design basis by enhancing standby electrical power to ensure the following regulatory requirements are met:

- Start an HPECI pump within 30 minutes of a LOBES event with no units surviving, and,
- Cooldown all reactors to <90C within 24 hours of a LOBES event with no units surviving.

Starting an HPECI pump within 30 minutes of a LOBES event with no units surviving is a regulatory requirement [reference NK30-CORR-00531-03030, 04Feb05 Letter, Schaubel to Mitchell]. Analysis indicates that a start within 45 minutes will meet the HPECI availability requirement, but a design requirement of 30 minutes is specified to allow appropriate engineering margins. As required by the HPECI unavailability analysis, an Auxiliary Power System ~~unavailability of 10^{-2} is required.~~

Cooldown of all reactors within 24 hours of a LOBES event with no units surviving is a regulatory requirement (Ref. memo NK30-CORR-50000-0140040, Aug 8, 2005, Guthrie to Froats, Attachment C). The 24 hours is a mutually agreed target between OPG/CNSC which is a derived requirement of adequacy to address the fact that the grid was not restored within the design basis assumption (1 hour). For cooldown the reliability has not been explicitly addressed. The design basis credits grid restoration within 1 hour and therefore the APS must have a high confidence to restore this design basis. Process system reliability of 10^{-2} is required, and there is no regulatory or engineering basis to provide less than 10^{-2}. Pickering A design basis for cooldown is thermosyphoning. Pickering B design basis for cooldown is PHT forced circulation.

The APS solution will therefore require an unavailability of 10^{-2} (3.5 days/yr) which will necessitate a total redundant system of 2x100%. Any solution with singleton components is ruled out since maintenance and outages would violate the unavailability target of 3.5 days/yr.

As an immediate compensatory action to allow the PNGS units to continue operation, the Remote Emergency Power Generator (REPG) was declared available for service on September 30, 2004. The REPG facility is designed to ensure a back-up power supply is available to operate an HPECI pump within 1.5 hours of a LOBES event. This REPG is situated on leased Hydro One property and is planned to remain in service until the APS has been declared available for service. Although this solution does not fully restore the design basis of the plant, the CNSC have accepted it as part of an overall LOBES event response until the APS is available. The current configuration of the REPG does not meet the 30 minute start time associated with the HPECI pump. Additionally, the REPG (Combustion Turbine Model TM2500) does not have sufficient capacity to support the regulatory requirements (IE HPECI start-up and PNGS-B reactor cooldown), as discussed in Section 3.

The APS must be able to support PNGS-B reactor cooldown within 24 hours and maintain HPECI availability (HPECI pumps must be operational within 30 minutes of a LOBES event) – this is a regulatory requirement. Additional APS design basis requirements, although not a regulatory requirement, include important station loads and spare Class III back-up loads (see section 5/ Qualitative Factors). An aero-derivative combustion turbine generating facility has been recommended as the preferred option to meet these requirements.

The cost estimate for the Auxiliary Power System is based on analysis of three major components of the facility, namely:

1. Power Plant – CTU facility located outside of the Pickering NGS protected area
2. 230 kV Connection – full load test transmission line from the Power Plant to the Unit 8 switchyard (all equipment located outside of the Pickering NGS protected area), as well as normal provision of APS power when the CTU is not running.
3. In Plant Boundary (IPB) work – all work associated with connecting the Power Plant to the Pickering Nuclear Station. The recommended connection is to the Station Electrical System (SES) bus at Unit 8.

Final contract negotiations are underway to engineer, procure and construct the APS Power Plant. High level estimates have been prepared and independently verified by a 3rd party for the 230kV and the Inside Plant Boundary (IPB) work.

A regulatory commitment is expected to be generated by the CNSC when the project schedule is submitted to the CNSC in January 2006. CNSC correspondence P-CORR-00531-01865 confirms the CNSC's expectation for installation of the auxiliary power supply.

2.1/ Progress to Date

1. **Power Plant**: A Steering Committee and Approval Committee for bid evaluations and negotiations was established. Bid evaluations by 2 Teams (Technical and Commercial) were conducted on the 3 proponents. After 2 iterations of bid evaluations, approval was received from the Steering Committee to begin negotiating with 2 of the 3 proponents. Based on negotiations, concurrence has been received to enter final negotiations with one of the proponents. The CTU choice has been finalized as the Pratt & Whitney FT4. A site visit was conducted to inspect the CTU's that OPG will be purchasing and the equipment meets OPG's expectations.
2. **230 kV Tie-in:** The 230kV tie is divided into 2 phases. Phase 1 is work required to be performed in the P681 Unit Outage, and, Phase 2 work connects the switchyard and the Power Plant. Phase 1 Design is close to completion. P681 Outage prerequisite work has commenced in the field. Phase 2 design is in progress.
3. **IPB:** Subsequent to the partial release BCS and the decision to lay-up P2 & P3, the CNO requested the project to revisit the cooldown methodology for Pickering A. The project analyzed the possibility of implementing a significant cost/schedule savings by connecting to the SES bus at U8, rather than the center of the SES bus. This greatly reduced the length of cable run and minimized IPB field work. ETAP studies have demonstrated that if cooldown is performed on Pickering A using Thermosyphoning, connecting to the SES at Unit 8 is achievable.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Do Nothing - Upgrade REPG Insitu (Regulatory Loads only) (Not Recommended)

This alternative is not recommended. PNGS does not currently meet its Design Basis. Design Basis assumptions (50% unit survivability and LOBES event duration <1hr) were demonstrated to be inaccurate after the August 14, 2003 LOBES event. Given that there is no evident practical way to limit grid collapse duration and the probability of such an occurrence cannot be demonstrated to be incredible, steps must be taken to restore the plants design basis. The CNSC have approved continued operation based on the APS design requirements being implemented in combination with the interim station LOBES event upgrades, including the installation of the temporary REPG (which by itself does not meet capacity requirements or redundancy requirements). In addition to the REPG not meeting the 30 minute startup time and the 10^{-2} unavailability target, the REPG has no margin to meet the load requirements and will not meet the starting KVA for the regulatory requirements. Additionally, the leased site at the Hydro One facility is not suitable for expansion to accommodate the 2x100% APS required to meet the 10^{-2} unavailability target. Finally, the REPG is subject to common mode fault on the 230kV line, by which an ice-storm could disable both the grid and alternate power supply. This would as a minimum require re-engineering, and disposition with CNSC. Due to the above facts, utilizing the REPG in-situ as part of the APS solution is not considered a viable option.

Other options for incorporating REPG into other alternatives are considered in alternatives 2a & 2b.

Alternative 1a – Install 2X100% CTUs Connected to Unit 8 SES Bus (Regulatory Loads Plus Important Loads) (Recommended)

This is the recommended alternative. Limit the duration of a station power outage by installing 2 x 100% duty aero-derivative combustion turbine units (CTU) and associated electrical system components to perform the function of an APS at Pickering NGS. This option is preferred as it will provide the most benefit, is flexible in operation and is a simple and reliable back-up power supply at the least cost. The CTU's capacity will meet the regulatory load requirements, specifically, HPECI and Reactor Cooldown. In addition the minimum sizing will allow for important additional loads to be supplied (see section 5/ Qualitative Factors).
The cost of this option is estimated at $99.7M, plus $17M contingency (total $116.7M). Efforts have been made to minimize cost by connecting to the end of SES bus at Unit 8. This will greatly reduce the work associated with the IPB and results in approximately $24M in savings, including $9.3 in contingency associated with the IPB work (refer to Attachment B for details).
230kV Tie-In: 230kV tie-in is required for full load testing and to supply power to the Power Plant auxiliaries. Additionally, it will allow for future peaking and emergency power to the grid (see section 5/ Qualitative Factors). The cost is $9.9M ($1.5M Phase 1 and $8.4M Phase 2, without contingency). Phase 1 work is the tie-in to the U8 230kV ring bus. It will require an extension to bus BUN, installation of a new disconnect, extensive civil work and the relocation of the U8 SST revenue metering CVT. Phase 2 involves connecting the Power Plant to the extended BUN bus. It includes the installation of a new 230kV breaker, a second new disconnect and all cabling. The cabling includes 230kV power cable, 600Vac auxiliary power/service cables, and instrumentation/control cabling for the power plant and circuit breaker protection. The underground cabling will require trenching and extensive civil work. An alternate means of providing auxiliary power and full load testing capability was investigated by (a) power supply to the CTU site/equipment from the local municipal utility (Veridian) and (b) full load testing of the CTUs through a set of load banks, either temporary or permanent. The estimated cost savings for the Veridian/load banks option is approximately $750k and is not recommended as it precludes the future peaking/emergency grid power operation.
Power Plant: The power plant is a commercial facility that is located outside the protected area. It will be built under an EPC (engineer, procure and construct contract) to minimize risk to OPG. The cost savings to build this

portion of the APS outside the protected area is estimated at $28M. Current estimate for the Power Plant including contingency is $59M (including contingency, refer to attachment B for details of variance from last BCS).

A regulatory risk has been identified with this option which is obtaining CNSC concurrence for cooldown on PA by Thermosyphoning (refer to Section 6).

Alternative 1b - Do Less – Install 2X100% CTUs Connected to Unit 8 SES (Regulatory Loads only) (Not Recommended)

Reduce the capacity of the APS system load requirements by eliminating non-regulatory loads, specifically, important CLIV loads and back-up power for CLIII loads, which are not a regulatory requirement. This option is not recommended as there are no appreciable economic benefits for the Power Plant as it would not change the size of the CTU selected. This is because the next lowest MW capacity CTU available would not meet the regulatory requirements (ie HPECI and PNGS-B Reactor Cooldown) and is therefore not an option. There is no significant cost savings with this alternative compared to the base case due to the minimum CTU size required for the regulatory loads. The projected cost savings for the lower MVA electrical distribution is estimated at $4M (smaller transformers/cables/switchgear). The cost of this option is $95.7M, plus $17M contingency (contingency is the same as the recommended alternative). The $4M savings compared to the recommended alternative is not recommended as the highly desirable loads (important CLIV loads and back-up CLIII power) could not be supplied. See section 5/ Qualitative Factors – item 2 for justification. Removing these loads would require CNSC disposition.

Alternative 1c - Do More – Install 2X100% CTUs Connected to Centre of SES (Regulatory Loads Plus Important Loads) (Not Recommended)

This option is the same as the recommended alternative for both the Power Plant and the 230kV connection, however, the IPB work involves connecting to the center of the SES bus. The postulated benefit would be full APS voltage delivery for PA units, including unencumbered PHT pump operation for cooldown. The cost of this option is $121.7M, plus $25.9M contingency. This is approximately $24M more than the recommended alternative (excluding contingency) due to increased costs associated with the IPB work and required OPG support. Additionally, the schedule is 4 weeks longer and there is considerably more risk associated with this option. This option is not recommended because cooldown on Pickering A can be achieved by Thermosyphoning and therefore the cost and schedule savings should be realized.

Alternative 2a – Other - Supplement REPG Connected to Ring Bus (Regulatory Loads only) (Not Recommended)

One of the alternatives investigated is to move the TM2500 from the existing REPG site and utilize it as part of the solution at the proposed site. This option would involve utilizing the existing SST transformer and tying into the 230kV ring bus. It would also require supplementing the TM2500 with a small generator to meet kVA requirements and purchasing a new LM2500/small generator pair to achieve the necessary 2x100% redundancy. Only regulatory loads would be met by this option. This option is not recommended because:

- It is not feasible from a technical perspective to utilize the 230kV grid supply. Engineering has confirmed that feeding station loads through both the APS transformer and the SST (station service transformer) in series will result in a large voltage drop. This is due to high impedance of the SST, which is required to minimize fault currents from the grid. Paralleling SSTs, by utilizing the 2 SSTs per ring bus was also reviewed to overcome the high impedance/voltage drop problem. This is not technically feasible because there would be no assurance that the impedances across the transformers are exactly the same and that voltages at the SES buses could be matched. A minor variation in voltages between SES buses BUE and BUF could cause severe uneven loading of a SST winding and damage the transformer. An additional reason is that the Station design does not allow two SSTs to simultaneously supply SES.

- If voltage drop is not overcome, it will cause the HTS (heat transport system) pumps, required for PNGS-B cooldown, to trip when they are started in standard configuration. As a minimum, the HTS pumps on PB would need to be started 1 pump at a time which could result in damage leading to pump failure. The cost of HTS upgrades to eliminate the single pump start-up failure risk is prohibitive (estimate a minimum of $27M to upgrade the HTS pumps and as much as a 2 to 3 year extension on the APS project schedule as it is all outage work – this would not be acceptable to the CNSC). Additionally, as the HTS pump work is extensive outage work, this would result in loss of generation as outages would increase in duration in the order of 30 days per unit (loss of generation >$67M for 4 units).
- The REPG is required to remain in service until the APS is declared in service. Under this alternative one CTU train would need to be commissioned prior to moving the TM2500 to proposed APS site. Not only would this extend the schedule by an estimated 14 weeks to allow the CTU power trains to be installed and commissioned separately, it would also drive the cost of the EPC contract up so that any savings realized by a smaller plant would be significantly reduced. A new request for proposal would be required for the power plant which would further impact schedule. Schedule and design requirement changes would require resolution with the CNSC.
- Risk strategy associated with EPC (engineer, procure, & construct) for the "Power Plant" portion would change as OPG would require EPC contractor to purchase the REPG TM2500 and design the Power Plant on this basis. Legal and Supply Chain have identified that it is key to minimize OPGs risk by limiting the equipment that is solely specified. This would limit the CTU choice to a TM2500 (only 15 world wide) or an LM2500.
- Highly desirable loads (important CLIV loads and back-up CLIII power) could not be supplied (see Qualitative Factors – item 2). Removing these loads would require CNSC disposition.

The estimated cost of this option is $126M, plus $28M contingency. In addition estimated loss of generation is $67M at regulated rates.

Alternative 2b – Other - Supplement REPG Connected to Secondary Side of SST (Regulatory Loads only) (Not Recommended)

One of the alternatives investigated is to move the TM2500 from the existing REPG site and utilize it as part of the solution at the proposed site. This option would involve installing 2 new 3 winding parallel test transformers with lower impedance and connecting to the secondary side of the SST to overcome the voltage drop problem. It would also require supplementing the TM2500 with a small generator to meet kVA requirements and purchasing a new LM2500/small generator pair to achieve the necessary 2x100% redundancy. Only regulatory loads would be met by this option. This option is not recommended because:

- Highly desirable loads (important CLIV loads and back-up CLIII power) could not be supplied. See section 5/ Qualitative Factors – item 2 for justification. Removing these loads would require CNSC disposition.
- Installing 2 new 3 winding parallel test transformers with lower impedance is technically possible, however, it has not been proven possible due to space constraints. Further engineering would be required to confirm feasibility. This could take up to 2 months.
- The installation of the transformers is U5 and U1 outage work which are both scheduled in spring of 2007. Schedule changes would require resolution with the CNSC.
- Additionally, there are other unknowns including long lead delivery on specialized non-standard transformer and a more complex operation due to electrical distribution.
- The REPG is required to remain in service until the APS is declared in service. Under this alternative one CTU train would need to be commissioned prior to moving the TM2500 to proposed APS site. Not only would this extend the schedule by an estimated 14 weeks to allow the CTU power trains to be installed and commissioned separately, it would also drive the cost of the EPC contract up so that any savings realized by a smaller plant would be eliminated. A new request for proposal would be required for the power plant which would further impact schedule. Schedule changes would require resolution with the CNSC.
- Risk strategy associated with EPC (engineer, procure, & construct) for the "Power Plant" portion would change as OPG would require EPC contractor to purchase the REPG TM2500 and design the Power Plant on this basis. Legal and Supply Chain have identified that it is key to minimize OPGs risk by limiting the equipment that is solely specified. This would limit the CTU choice to a TM2500 (only 15 world wide) or an LM2500.

The estimated cost of this option is $130M, plus $26.5M contingency.

Alternative 3 – Other – 1x100% APS (Not Recommended)

Install only a 1x100% system. This is not recommended as it will not meet the 10^{-2} unavailability requirement and would require a change to the APS Design Requirements. The design basis credits grid restoration within 1 hour and therefore the APS must have a high confidence to restore this design basis. Process system availability of 10^{-2} is required, and there is no regulatory or engineering basis to provide less than 10^{-2} (Ref. memo NK30-CORR-50000-0140040, Aug 8, 2005, Guthrie to Froats, Attachment C). Additionally, the CNSC security requirements approval to place the APS power plant outside the protected area was based on a 2x100% APS system.

#	Cost Summary Table Description of Alternative	Cost of Alternative $M No contingency	With Contingency
0	Do Nothing - Upgrade REPG Insitu (Regulatory Loads only)	N/A	N/A
1a	**Alternative 1a RECOMMENDED– Install 2X100% CTUs Connected to Unit 8 SES Bus (Regulatory Loads Plus Important Loads)**	**99.7**	**116.7**
1b	Alternative 1b - Do Less – Install 2X100% CTUs Connected to Unit 8 SES (Regulatory Loads only)	95.7	112.7
1c	Alternative 1c - Do More – Install 2X100% CTUs Connected to Centre of SES (Regulatory Loads Plus Important Loads)	121.7	147.8
2a	Alternative 2a – Other - Supplement REPG Connected to Ring Bus (Regulatory Loads only)	126 (see Note 2)	154
2b	Alternative 2b – Other - Supplement REPG Connected to Secondary Side of SST (Regulatory Loads only)	130 (see Note 3)	156.5
3	1x100% APS	N/A	N/A

NOTES:

1) With the recent decision to not restart P2/P3 utilizing the SGs (standby generators) was reviewed. This is option cannot be pursued because:

- The SGs are currently required to support P2/P3 until the units have been de-fueled. This will result in a schedule extension that is unacceptable.
- The SGs are only 5MW and the associated electrical distribution is not of sufficient capacity to provide appreciable benefit.
- The existing foot print for the SGs is not large enough to expand for the APS.

~~2) The cost for the primary heat transport modification is $126M plus and estimated 180 days of lost generation~~ $67M, due to extended outages to perform PHT modifications.

3) There are execution risks associated with this alternative, some of which may not be resolvable (refer to Alternative 2b description for details).

4/ THE PROPOSAL

It is recommended to install an APS consisting of 2 CTU's complete with 2 fully redundant 100% power trains to meet the unavailability target of 10^{-2}. The CTU's will be equipped with auto start capability and each power train will have a capacity of approximately 36 MW at 35°C. This will allow the CTU to supply:

- regulatory loads (HPECI and reactor cooldown – PB PHT forced circulation, PA Thermosyphoning),
- important CLIV loads (see section 5/ Qualitative Factors), and,
- spare CLIII back-up power.

The generator output voltage will be 13.8kV. Each train has independent fuel storage (capacity for 24 hours plus contingency with on line fueling capability), forwarding and injection systems with sufficient inventory to meet the minimum mission time of 24 hours. The 13.8kV electrical output is routed through switchgear, then through the nuclear power plant boundary to 4.16kV transformers, and is then connected to the 4.16kV plant electrical distribution system via the Unit 8 section of the Site Electrical System (SES) buses. In addition, a separate line will be run from the CTU's output through switchgear and a 230kV transformer to connect to the 230kV Ontario electrical grid. This connection will be used to supply power to the APS system auxiliaries while the CTUs are not operating, and to allow for full load testing of the CTUs via the 230kV system. In the event that the CTUs are without power from the electrical grid, they shall be able to be black-started.

To facilitate coordination and execution of the APS Project, it has been divided into 4 major parts as follows:

1) Power Plant – the commercial facility located in the East complex. It is an EPC contract and includes 2 CTU's, 13.8 kV switchgear, 13.8/230kV transformer, auxiliary systems and fuel forwarding systems.
2) IPB (Inside Plant Boundary) – this is all the work located inside the nuclear security fence. It includes extensive cable runs and the 13.8/4kV electrical distribution equipment which will tie in to the Unit 8 Station Electrical System (SES).
3) 230kV Phase 1 – This is the electrical tie in to the existing Hydro One 230 kV switchyard. This work is required for full load testing and must be done in a unit outage. The scope includes a 230kV bus extension, revenue metering relocation and 230kV circuit breaker/disconnect installation.
4) 230kV Phase 2- This is a 230kV cable run in the east complex that will connect the Power Plant (13.8/230kV transformer) to the Hydro One switchyard (Phase 1).

Milestones Finish Date (D/M/Y)	Description
20/10/05	Outside – EPC – Agency Approval to issue PO (complete)
25/10/05	Start of Installation (complete)
15/12/05	Full Release Funding of APS Project
21/04/06	P681 230kV Switchyard Available for Service Declaration complete.
30/05/06	Design Complete
15/06/06	All Major Contracts Awarded
19/02/07	All Regulatory Approvals Obtained
13/04/07	Power Plant – Mechanical Completion Finished
16/07/07	Power Plant – Substantial Completion Finished
27/07/07	APS Available for Service
28/09/07	In Service Declaration to CNSC

5/ QUALITATIVE FACTORS

1) The 230kV full load connection will allow for future peaking and emergency grid power operation. This option would require an environmental assessment that would extend the in-service date. Additionally, the CNSC would need to review/approve operation of the plant for emergency grid power operation. It is anticipated that this schedule extension would not be accepted by the CNSC. There is currently no business case to run the plant for revenue. This is because the plant may be subject to the Nuclear regulated cap price (4.95c/kWh regulated price), and the operating costs would exceed the generated revenue. Costing of these options (peaking/emergency grid operation) was not pursued, however, the 230kV connection will allow for future expansion at minimal costs and would be the subject of a separate business case.

2) The minimum CTU size which will meet the regulatory requirements, has sufficient excess capacity such that at minimal incremental cost to the project the following highly desirable loads can be supplied:

- important CLIV loads (approximately 8.8MW), and,
- back-up for CLIII loads (approximately 5.7MW).

The important CLIV loads, although not a regulatory requirement, support operation should CLIV power be totally lost throughout the plant. Important CLIV loads include:

- Main Control Room (MCR) & Control Equipment Room HVAC: Availability of these loads will eliminate thermal risks posed on Digital Control Computers and provide MCR temperature control during a LOBES event. If we were to lose both Units computers the ANO would have to monitor his Unit by Alarm windows only and increased operator field surveillance. This would significantly challenge the capability of operator resources during a LOBES/CLIV power event. Further, ANO comfort during a LOBES event is important.
- Standby Boiler System: The support systems of the oil fired Standby Boiler System operates on CLIV power. If LOBES occurs during winter months this will be required to supplement building heating. Without building heating for prolonged period of time we could possibly freeze/burst instrumentation lines thereby making it impossible to monitor that system and perform safe operation. Additionally we could ~~possibly freeze fire protection lines and drums of D20 stored throughout the station.~~
- Chemistry Labs (Labs cannot function without CLIV power). The chemistry labs are required to place the units in the guaranteed shutdown state.

Back-up power to critical CLIII loads includes, Auxiliary Boiler Feed Pump (ABFP), Auxiliary Condensate Extraction Pump (ACEP), Emergency High Pressure Service Water Pump (EHPSW) and Emergency Low Pressure Service Water Pump (ELPSW). Because the LOBES event lasted longer than 1 hour, the adequate operation of critical CLIII loads became paramount. The failure of an ABFP or an ACEP leaves the Emergency Water System as the next barrier (severe economic impact). Furthermore, failure of the EHPSW pump or LPSW pump could cause significant process system damage and impairment of the fire protection system.

3) The requirement to have an HPECI pump running within 30 minutes sets the minimum start time for each CTU. However, at no incremental costs to the project a start time in the range of 3 minutes can be accommodated by the selected CTUs. This provides business advantage for future availability of Pickering A units if the Pickering B units are shutdown for either retube or end of life. Currently Pickering A units are not credited for SES. However, with the start time of the CTUs in the range of 3 minutes and additional analysis, Pickering A units could potentially continue operation even after Pickering B units are shutdown. It should be emphasized that further analysis is required and the APS alone cannot assure this future capability.

6/ RISKS

To facilitate coordination and execution of the APS Project, it has been divided into 4 major parts as follows:

1. **Power Plant** – the commercial facility located in the East complex. It is an EPC contract and includes 2 CTU's, 13.8 kV switchgear, 13.8/230kV transformer, auxiliary systems and fuel forwarding systems.

2. **IPB (Inside Plant Boundary)** – this is all the work located inside the nuclear security fence. It includes cable runs and the 13.8/4kV electrical distribution equipment which will tie in to the Unit 8 Station Electrical System (SES).

3. **230kV Phase 1** – This is the electrical tie in to the existing Hydro One 230 kV switchyard. This work is required for full load testing and must be done in a unit outage. The scope includes a 230kV bus extension, revenue metering relocation and 230kV circuit breaker/disconnect installation.

4. **230kV Phase 2**- This is a 230kV cable run in the east complex that will connect the Power Plant (13.8/230kV transformer) to the Hydro One switchyard (Phase 1).

Each risk shown in this section is identified as belonging to one of the above 4 sections. The total money allocated for contingency in each of the 4 areas is as follows:

1) Power Plant ($11.3% contingency allocated): Specific contingency $3.6M, General contingency $2.4M, Total contingency $6M
2) IPB (28.8% contingency allocated): Specific contingency $1.4M, General contingency $4.5M, Total contingency $5.9M.
3) 230kV Phase 1 (33.3% contingency allocated): General/Total contingency: $0.5M
4) 230kV Phase 2 (32.1% contingency allocated): Specific contingency $1.1M, General contingency $1.6M, ~~Total contingency $2.7M~~
5) In addition there is $1.9M of contingency allocated for interest, escalation and OPG resources (refer to Attachment A).

The following table identifies risks that are greater than "LOW" and form key risks and mitigating actions for the APS project. For a complete list of updated risks refer to Attachment D. Note that all Power Plant risks indicated as Medium in the Partial BCS have now been dispositioned as LOW. The sole remaining Medium risk is Regulatory in nature.

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
General: CNSC requirement to cool all units below 90°C in 24 hours. Cooldown methodology may not be acceptable to CNSC.	Extensive delays and cost to move the station tie-in point to centre section of SES buses.	**High**	• Senior Management is aware of risk. High level strategy being developed to communicate PA Thermosyphoning Design Requirement to CNSC. • Thermosyphoning is a recognized method of cooldown and OPG is confident it will meet the mission based on OPEX • Electrical analysis is in progress to determine load profile impact using forced circulation cooldown on PNGS-A. • Additional cost to tie-in to SES centre section is $24M.	**Medium**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	September 2007	February 2008	Director, PB Station Engineering

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	APS Declared I/S	Not installed	Successful Commissioning	Accepted at Final AFS	PNGS Station (Project Sponsor-Mark Elliott)
2.	CNSC	Final date for CNSC Commitment is expected to be assigned in January 2006	Meeting commitment	Documentation of approval	PB Senior VP
3.					
4.					
5.					

Auxiliary Power System 13 - 49104

Full Release Business Case Summary P-BCS-50000-00004-R000

Attachment "A"

Project Cost Summary

$ Millions Capital	LTD Prior Years 2004	2005	2006	2007	2008	2009	Total	LTD This Mth Oct 2005	LTD %
OPG Resources		1.3	3.0	2.8	0.3		7.5		
Power Plant		11.4	37.0	4.6	0.0		53.0		
230kV Phase 1		0.8	0.7	0.0	0.0		1.5		
230kV Phase 2		0.2	6.3	1.9	0.0		8.4		
Inside Plant Boundary (IPB)		2.4	10.5	7.6	0.0		20.5		
Misc. - Contract		0.2	0.5	0.0	0.0		0.7		
Escalation		0.0	2.4	0.3			2.7		
Interest (Capital Project Only)		0.1	3.5	1.9	0.0		5.5		
Sub Total - (excl Contingency)	0.0	16.4	63.9	19.1	0.3	0.0	99.7	3.3	3.3%
OPG Resources		0.0	1.0	0.9	0.0		1.9		
Power Plant		0.0	4.8	1.2	0.0		6.0		
230kV Phase 1 (Swyd tie-in)		0.1	0.4	0.0	0.0		0.5		
230kV Phase 2		0.1	1.7	0.9	0.0		2.7		
Inside Plant Boundary (IPB)		0.0	3.0	2.9	0.0		5.9		
Sub Total - Contingency		0.2	10.9	5.9	0.0	0.0	17.0		
Grand Total	0.0	16.6	74.8	25.0	0.3	0.0	116.7	N/A	N/A
2005-2009 Business Plan		45.0	100.0	55.0	0.0		200.0	N/A	N/A
Variance to Business Plan - (excl Contingency)	0.0	(28.6)	(36.2)	(35.9)	0.3	0.0	(100.3)	N/A	N/A

Removal Costs included in above	0
Definition Costs included in above	0
Estimate Name, Quality, etc	Budget Quality +30/-15%
Design Complete:	10%

Reviewed By:

Scott Guthrie
Project Manager

Nov 4/05
Date:

Approved By:

Mark Arnone
Director Projects and Modifications (Strat V)

Date

Attachment B
Cost Comparison of Options Based on Partial Release vs. Full Release BCS

$ Millions Capital	Last BCS	This BCS	Variance Explanation
OPG Resources	9.5	7.5	$2.0M reduction due to reduced scope due to Unit 8 SES tie-in
Power Plant	64.9	53.0	$11.9M reduction due to advanced negotiations.
230kV Phase 1	1.5	1.5	no change
230kV Phase 2	8.1	8.4	$0.3M increase due to improved estimates.
Inside Plant Boundary (IPB)	37.8	20.5	$17.3M reductin due to reduced scope due to Unit 8 SES tie-in.
Misc. - Contract	0.9	0.7	$0.2M reduction due to reduced scope due to Unit 8 SES tie-in.
Escalation	3.4	2.7	$0.7M reduction due to lower costs (38% reduction due to Power Plant, 62% due to Unit 8 SES tie-in).
Interest (Capital Project Only)	7.0	5.5	$1.5M reduction due to lower costs (38% reduction due to Power Plant, 62% due to Unit 8 SES tie-in).
Sub Total - (excl Contingency)	**133.1**	**99.7**	
OPG Resources	3.5	1.9	$1.6M reduction due to reduced scope due to Unit 8 SES tie-in
Power Plant	8.1	6.0	$2.1M reduction due to advanced negotiations.
230kV Phase 1 (Swyd tie-in)	0.5	0.5	no change
230kV Phase 2	2.7	2.7	no change
Inside Plant Boundary (IPB)	13.2	5.9	$7.3M reduction due to reduced scope due to Unit 8 SES tie-in
Sub Total - Contingency	**28.0**	**17.0**	
Grand Total	**161.1**	**116.7**	

Attachment C

NK30-CORR-50000-0140040

"Regulatory Requirement for Unit Cooldown – Auxiliary Power System"

Passport Record #: NK30-CORR-50000-0140040

August 8, 2005

J.P. Froats
Vice President Engineering and Modifications
and Chief Nuclear Engineer

Subject: **Regulatory Requirement for Unit Cooldown – Auxiliary Power System**

The purpose of this memorandum is to confirm the regulatory basis for the Pickering unit cooldown requirements as applicable to the Auxiliary Power System (APS) project. The APS is intended to provide power to Pickering NGS during a Loss of Bulk Electrical System (LOBES) event with shutdown of all operating units.

At a meeting with my staff on August 4, 2005, you clarified the origin of the unit cooldown requirement and provided context on the regulatory environment surrounding this issue. The following points were made:

- The original plant design basis assumed that restoration of grid power to Pickering NGS following a LOBES event would be prompt (approximately 1 hour, with a high confidence level). Thus, reliance on grid supplied power to cooldown the reactor heat transport systems (HTS), following grid power restoration, was considered acceptable.
- The August 2003 LOBES event challenged the assumption of grid restoration timing. Thermosyphoning as a means of acceptable fuel cooling is limited in time duration. To resolve this issue, OPG and the CNSC came to an agreement that a system, independent of the grid, would be provided to support reactor HTS cooldown following a LOBES event. OPG and the CNSC also agreed that following a LOBES event with no units surviving to supply site Class IV power, all of the Pickering units should have their HTSs cooled to <90C within 24 hours of the LOBES event.
- The requirement for HTS cooldown within 24 hours of a LOBES event with no units surviving is a derived requirement of adequacy to address the fact that the original design basis assumption of grid restoration time now appears to be non-conservative.
- The unavailability of the post-LOBES cooldown function, supplied by the new APS, should be 10^{-2}, in line with requirements for process systems important for fuel cooling.

In summary, it is a regulatory requirement for all Pickering unit HTSs to be cooled to <90C within 24 hours of a LOBES event with no units surviving. The new Pickering APS will supply adequate power to Pickering NGS to support this requirement.

Submitted By: ORIGINAL SIGNED
S. Guthrie
Manager
Auxiliary Power System Project

Concurred By: ORIGINAL SIGNED
J.P. Froats
Vice President Engineering and Modifications and Chief Nuclear Engineer

cc: M. Arnone
K. Shore
D. Williams
M. Ruffolo
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G. Brown

Attachment D

"Complete Risk Table for APS Project"

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Power Plant – successful EPC (engineer, procure & construct) contractor unable to retain reservation on CTU's that have been submitted as part of the EPC Power Plant bid.	Cost savings have been realized by reserve refurbished CTU's as part of EPC bid. CTU's have been reserved, but will not be secured until BoD release received. If CTU's are sold to another customer before funds approved this may result in high CTU costs.	**Medium**	• Working with potential contractors to develop plan to retain CTU's. • OPG expects that we would get the right for first refusal. • OPG conducted site visit and confirmed reserved CTU's meet OPG expectations. • If decision is to not reserve CTU, expected cost increase due to impaired negotiating position is $5-10M.	**Low**
Power Plant – Construction Specs will be issued with cross reference to OPG guidelines.	Higher costs may result due to inadvertent compliance with Nuclear standards.	**Medium**	• Design will review Construction Specifications prior to Contractor purchasing equipment.	**Low**
Power Plant - Work Protection (WP) after system tie-ins will be completed under OPG policy.	Contractor work will be impacted affecting cost and schedule if correction work required post tie-in.	**Medium**	• Delay tie-ins until absolutely necessary. • Ensure contractor aware of schedule risk.	**Low**
Power Plant – Specific tie-in location to services not identified.	Additional costs for work associated with service tie-ins may be considered an extra by Contractor.	**Medium**	• The Project is working with Facilities-Engineering to minimize the impact.	**Low**
Power Plant – Outstanding Project decision. It is not confirmed who will operate the Power Plant.	Uncertainty in training and documentation costs depending who operates the plant.	**Medium**	• Memo outlining operating strategy options is being routed to Senior Management to expedite decision. Path forward proposed based on recommendation. • Training, documentation and equipment are based on Non-nuclear staff (IE Commercial facility). If nuclear facility upgrades required, expected cost increase is $5-15M.	**Low**
Power Plant proposed Power Plant foundation used to be site of old Municipal WTP	Unknowns may increase construction costs	**Medium**	• Perform Geotechnical survey to identify the unknowns as much as possible and allocate contingency funding based on survey results	**Low**
Power Plant - APS Power Plant spare parts - cost unknown	May exceed budgeted amount and increase project total cost	**Medium**	• Minimize spare part inventory by having Design review recommended spare part list. • High level estimate for spare parts included.	**Low**

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Power Plant – Costs to replace parking lot taken by APS site.	Costs may increase depending on proposed solution.	**Medium**	• Working with Facilities to develop a plan to replace 350 parking spots that will be lost to Power Plant site. • High level estimate for parking lot included ($1.5M)	**Low**
230kv Phase 2 - Estimates only available for 230kV phase 2 based on conceptual design.	Costs may increase up to 60%.	**Medium**	• Helyar provided more detailed cost estimates. • High level contingency allocated (50%). • Inside Design Agency SNC to prepare design.	**Low**
230kV Phase 1 - accuracy of estimate.	Hydro One provided an estimate for Phase 1 EPC work. However, OPG would be charged Hydro One's actual costs, regardless of how far off those costs are from the estimate. Hydro One's estimate was not a detailed breakdown, so OPG cannot assess the potential for additional costs. In addition, Hydro One staff that normally do the estimating are on strike, so the accuracy of the estimate is in question.	**Medium**	• Working with Hydro One to obtain more information on estimate. • Allowing $900k (90%) in contingency	**Low**
IPB – Accuracy of estimate for IPB based on 10% Engineering.	Estimate accuracy is based on 10% Engineering complete.	**Medium**	• Arranged for Design Contractor to develop estimate and Field Contractors to input/validate.	**Low**
General -Uncommitted pricing by vendors	Increase cost of project	**Medium**	• Conservative values of 3% escalation and 6% interest assumed.	**Low**
General - Changing market conditions, cost escalations, interest rate increase	Project cost increased	**Medium**	• OPG to carry the cost escalation, rate increase contingencies to have a cushion for the project cost increase due to these factors	**Low**
General – delay costs associated with obtaining security clearances for contractors.	Can lead to project cost increase	**Medium**	• Allocating cost and resources to the issue. • Working with the CMO Department to ensure Security Clearances for Contractors will be expedited.	**Low**
230kV Phase 1 – New breaker bay may require significant	If new breaker bay is installed close to U8 metering shed this	**Medium**	• Reviewing with Engineering/Hydro One if access to U8 Metering Shed roof required.	**Low**

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
shoring due to sloped grade.	will eliminate access U8 metering shed roof except for Bus N outages (every 2 years). Option is to install new breaker bay further from U8 metering shed, but significant shoring required due to sloped grade.		• Estimated costs at $250k for shoring. Included in contingency money allocated for 230kV Phase 1 (100%).	
Power Plant – cost for demobilization and remobilization due to IPB schedule delays.	Final commissioning cannot take place until IPB is complete. If this is delayed, it may require the EPC contractor to demobilize, and then remobilize when ready for final commissioning.	**Medium**	• Expediting operating work. Planning critical path. • Contract language to minimize penalty due to potential schedule delays. • Station Management is aware of the risk and is committed to maintaining critical path.	**Low**
General – New scope due to existing PNGS plant material condition degradation.	Additional cost and schedule delay.	**Medium**	• Minor discovery work additions will be managed via use of contingency fund allocated to the project. Any major discovery work will be treated as a separate project.	**Low**
General – 230kV tie-in will require connections to station electrical protection system. This work must be done live and there is a potential for unit trip due to human performance.	Unit outage due to line trip.	**Medium**	• Ensure all precautions are taken in workplan to ensure human performance issues are addressed.	**Low**
General – Decision required to confirm who will operate plant (Nuclear or Non-nuclear staff)	Scope of project would change considerable (IPB and Power Plant). Remote Annunciation room inside plant is required if Nuclear operators, Power Plant requirements will increase.	**Medium**	• Memo routed to PNGS Senior Management to expedite decision.	**Low**
General - Design Engineering completion dates are not achieved	Delay in installation dates. Delay in design may result in	**Medium**	• Project and Design schedule integrated under one cost & schedule analyst.	**Low**

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
	schedule delay which could impact CNSC commitment.		• Expediting long lead item procurement to minimize impact on design schedule • Reviewing resources allocation • Cost impact covered by contingency.	
General - Considerable coordination efforts required by Operations for the 230kV and 4.16 kV tie-ins, and HPECI dynamic testing.	May impact schedule	**Medium**	• Project has an Operations SPOC and is working closely with the OPS group to ensure communication is effective. • Operations SPOC attends Project meetings on a regular basis. • Allocated 3 weeks to complete final HPECI test.	**Low**
230kV Phase 1– purchase and delivery of long lead items	Miss unit 8 SST outage in March 2006 for tie-in work	**High**	• Negotiate with Hydro One Management for procurement of long lead items and obtain approval to purchase during detailed design (prior to full release)	**Low**
IPB - Late delivery of material	Affect schedule and delay the overall completion target date.	**Medium**	• Critical material delivery dates to be highlighted in the project schedule • PO to mention the target delivery dates. • Align OPG Supply SPOC with Project contingency actions.	**Low**
IPB - Low field productivity by contractor due to Nuclear processes.	Affect schedule and delay the overall completion target date.	**Medium**	• Reviewing operating procedure and applying TCN's as required. • The productivity of the project to be monitored/controlled via task spread sheets. • Contract Administration/ Monitors and Projects to anticipate barriers and proactively resolve	**Low**
General - Winter working conditions for the civil works	Delay in project schedule	**Low**	Install and Commissioning Plan to confirm critical activities that are weather dependent to ensure contingency actions are in place.	**Low**
General – APS will not be I/S prior to the REPG (temporary solution) lease from Hydro One expiring in 2006.	No standby power available to support a LOBES event.	**Low**	• Negotiate extension of lease with Hydro One to ensure REPG remains I/S until the APS is declared I/S.	**Low**

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
IPB – Station System Configuration that will prevent installations/ commissioning.	System configuration (eg. ECI, SES, Quiet Mode operation) may prevent progressing SES bus outage tie-ins, HPECI pump test runs etc. Delay in installation implies missed CNSC commitment.	**Medium**	• Planning the inside the plant work in detail. Working with operating/Outage to ensure the station system configuration will permit installation/commissioning as planned.	**Low**
General – PNGS Environmental CofA amendment may be required for procurement of CTU's.	Environmental CofA amendment may hold up finalizing CTU's and impact design schedule.	**High**	• Team approach with EPC Contractor, Project and Environmental group to ensure CofA is amended with priority.	**Low**
General – Proposed schedule does not meet governance. P681 outage milestones not met. Not all operating work milestones will be met.	Impact is schedule extension. Missed CNSC commitment.	**Medium**	• Station commitment to prioritization of work. • Contingency funding has been allocated to ensure schedule can be maintained.	**Low**
General – Sufficient Supply resources to support multiple Contracts for the APS	There are at least 7 new contracts associated with the APS project of which several are of significant size (EPC Power Plant $>50M, 230kV Phase 2 $8M, IPB Construction ~$37M)	**Medium**	• Prioritizing Contracts to utilize limited Supply resources. • Supply Chain/Law Division are aware of risk and agree that contract schedule should be achievable.	**Low**
General – Redesign to meet changing regulatory requirements	The project design may change	**Medium**	• Monthly meetings with CNSC	**Low**
General – Electrical ETAP analysis supporting transformer location outside Protected Area is still unverified.	The design may change resulting in cost or schedule impact.	**Medium**	• Analysis was done by an experienced Design Engineer and has been reviewed by their supervision. • Design has a high level of confidence that the analysis supports the current design proposal.	**Low**
General - Unforeseen station systems interface issues	Lead to delays	**Medium**	• Reviewing system interface issues with Performance Engineering and Nuclear Safety. • Schedule for SES bus tie-in to be determined in	**Low**

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
			accordance with planned unit and SG outage schedules for both Pickering A and Pickering B.	
General - Legacy issues/change in the site conditions	May cause delay in the project	**Medium**	• Legacy issues to be overcome by thoroughly reviewing the site conditions for existing installations. APS installation procedures to be laid out incorporating all the site conditions and adjacent areas.	**Low**
IPB – cable routing to connect Power Plant to Station will go over outfall. This design must meet security requirements to ensure no risk of common mode fault.	Security does not approve the design. Rework is required.	**Medium**	• Designing to meet common mode criteria	**Low**
General: CNSC requirement to cool all units below 90°C in 24 hours. Cooldown methodology may not be acceptable to CNSC.	Extensive delays and cost to move the station tie-in point to centre section of SES buses.	**High**	• Senior Management is aware of risk. Senior Management meeting has been arranged for Nov2 to develop strategy on CNSC concurrence for Thermosyphoning. • Thermosyphoning is a recognized method of cooldown and OPG is confident it will meet the mission based on OPEX • Electrical analysis is in progress to determine load profile impact using forced circulation cooldown on PNGS-A. • Additional cost to tie-in to SES centre section is $24M.	**Medium**
IESO – may have to generator excitation from brushless type to static excitation.	Replace generator excitation on both CTU generators.	**Medium**	Met with IESO and IESO noted that CTU-generator set with brushless exciters are not preferred if they are used for generation/peaking. However, it is not a concern if it is used for standby emergency power only. • Estimated @ $2M ($1M/generator)	**Low**
Power Plant/230kV – Having all required Market Participation Licences & Agreements in place	Delay in-service date.	**Medium**	Pursue ASAP the following: • Connection agreement from IESO • TCA and switchyard lease agreements amended • Approvals to cross outfall (identified as Coast Guard	**Low**

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
			and Metro Toronto Conservation Authority	
Power Plant – Having CofA to cover APS Power Plant emissions.	Delay in-service Date	**Medium**	• Expedite application of CofA once Power Plant configuration confirmed to ensure commissioning schedule is not delayed.	**Low**
General – Timeliness in getting contractors' staff trained for plant access and radiation protection	Potential delay in start of work.	**Medium**	• Use pre-approved (EH&S certified) contractor(s) and their work force where possible. • Training plan to coordinate & plan required activities.	**Low**
IPB – Heat stress while working inside the plant, eg, during cable installation at U8 SES tie-in	Productivity	**Medium**	• Schedule work during cooler months of the year per Installation & Commissioning Plan objective.	**Low**
General – risk that APS will not perform intended function.	Potential failures due to project interfaces	**Low**	OPG Design is reviewing all interface issues to ensure APS meets Design Requirements and specifications.	**Low**

Standby Generator Governor Upgrades Pickering B 13 - 49109 Capital 13 - 40528 OM&A

Full Release (Phase 2) Business Case Summary NK30-BCS-54600-00011-R000

1/ RECOMMENDATION:

We recommend a Phase 2 release of $8.8M (total project $23.3M) to complete the design, comprehensive installation work packages and installation/commissioning of governors on the remaining four (of six) Pickering B Standby Generators (SG's).

This project is one of five SG Upgrade projects designed to reduce the likelihood of a forced outage due to SG obsolescence and spare parts unavailability that has been negatively impacting reliability. The scope of these projects was based on a Pratt & Whitney (P&W) report IMR # 510 issued in May 1999 which focused on equipment obsolescence issues and the OEM's inability to support critical products. Phase 2 of this project ($8.8M) and the Protective Relay project ($1.8M) are the two outstanding initiatives of the overall program that is estimated to cost $50M. We have a REGM target to complete this work by Dec 31, 2007.

Prior to the start of this initiative, Pickering B SG performance indicated a deteriorating trend. We were not able to consistently meet the design basis SG start reliability. Approximately 70% of the total SG trips identified in the P&W report could have been prevented by the SG Governor upgrade by ensuring consistent SG starting time bench marks within the start permissive logic. Continued degradation has the potential of severe, protracted adverse impact on SG performance and forced unit outages due to unavailability of Standby Class III Power redundancy. Forced shutdowns of operational Nuclear units can occur when SG unavailability is combined with other safety support system degradation, functional failures or operational restrictions (such as Class II UPS and SES).

At this time, two (2) Governors have been installed, placed in service, and a Post Implementation Reviews (PIR) has been completed. We have seen improvements in SG performance, as work has progressed and the SG health system has recently changed from RED to WHITE. Project completion is a requirement to maintain system health WHITE assessment. The total project estimate has increased $1.2M to $23.3M, due primarily to Vendor QA issues, material costs, and underestimated design costs. Lessons learned from Phase 1 have been incorporated into the Phase 2 estimate.

The current Integrated Operating Plan (IOP) schedule calls for the completion of four (4) SGs in 2007. However, due to the degree of difficulty in executing four installations in one year, we are recommending the installation of three (3) governors in 2007 and one early in 2008. This will involve an adjustment to the IOP schedule and an extension to the REGM commitment. However, if conditions prove favourable, we will install four (4) units in 2007.

$000's (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	Full - Phase 1	2,672	8,850	2,969	-				14,491
Requested Now	Full - Phase 2	-	(1,186)	6,984	3,042				8,840
Future Funding Req'd	None								-
Total Project Costs		2,672	7,664	9,953	3,042	-	-	-	23,331
Other Costs									-
Ongoing Costs									-
Grand Total		2,672	7,664	9,953	3,042	-	-	-	23,331

Investment Type	Class	Breakeven Level of Risk	IRR	Discounted Payback
Sustaining	Cap & OM&A	5.2% forced outage	N/A	N/A

Submitted By:

Feb 27/07

Pierre Tremblay
Senior Site Vice President, Pickering B

Date:

Approved by: M Mitchell

T.N. Mitchell
Chief Nuclear Officer

Finance Approval:

Feb 18/07

D. Power
V. P. Corporate Investment Planning

Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Mar 5/07

Jim Hankinson
President and CEO

Date:

2/ BACKGROUND & ISSUES

The Standby Generator Health system was rated as RED as recently as Q1 2006 due to functional failures on aging parts that are obsolete and no longer supported by the OEM. Over the last few years the SGs have experienced a number of functional failures that contributed to forced outages. The functional failures reduce redundancy and potentially could lead to a Pickering B units shutdown. Recent upgrades and maintenance have improved the system health rating from RED (Q1) to YELLOW (Q2/3) to WHITE (Q4). Project completion is required to ensure system reliability and resolve obsolescence of the governor system which is not supported by the OEM.

The SG system is an essential safety related support system which supplies Class III power to the electrical equipment required to ensure a safe shutdown of the reactor; continuous core cooling, and supply to essential loads in the turbine, water and air systems, in the event of loss of Class IV power. There are three SGs that support each pair of Pickering units (i.e. 056-54600-SG1/SG2/SG3 supports Units 5 & 6, and 078-54600-SG1/SG2/SG3 supports Units 7 & 8).

As per Abnormal Incidence Manual (NK30-AIM-058-09013-04.01), following are the impairments for the Standby Generator system:

- Coincidental unavailability of three SGs per pair of units will result in SG system impairment (system does not meet design intent). In this impairment, both Pickering B affected Units need to be shutdown within 24 hours unless approval has been given by the Duty Manager for continued operation beyond 24 hours. The minimum system requirement is to have at least one SG available per pair of units.

- If two of the three SGs are unavailable per pair of units, the system will be considered to have reduced redundancy or margin of safety and required action will be to suspend testing of remaining SGs and repair to be carried out on high priority basis for the affected SG.

- If one of the three SGs is unavailable per pair of units, the system will be considered to have reduced redundancy or margin of safety and required action will be to suspend non-emergency operation of remaining SGs above 3.5MWe in peaking mode and repair to be carried out on high priority basis for the affected SG.

The following projects represent the Pickering B SG Upgrade program:

Pickering B Standby Generator Upgrade Projects				
49033	SES/HPECI Power Supply Upgrade	Capital	12.7	Complete
49088	Standby Generator Upgrade	OM&A	1.0	Near Completion
40412	Standby Generator Upgrade	Capital	11.0	Near Completion
40628	New Protective Relays	Capital	1.8	Developmental Stage
49109 /40528	Standby Generator Governor Upgrade	Capital / OM&A	23.3	2 of 6 complete
Total			49.8	

See Attachment 'D' for summary of Pickering B SG functional failures extracted from the System Health Report.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Stop the Project	Alt 1 (Recommended)		Alt 2	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost	Delay 1 yr			
Revenue	(16,265)	(1,857)	(1,857)	(3,778)			
OM&A	(9,847)	(2,466)	(2,007)	(2,316)			
Capital	1,477	(22,872)	(12,995)	(13,385)			
NPV (after tax)	(12,401)	(20,782)	(12,401)	(13,353)			
Impact on Economic Value (IEV)	N/A	(8,381)	-	(952)			
IRR%	N/A	N/A	N/A	N/A			
Discounted Payback (Yrs)	N/A	N/A	N/A	N/A			

Stop the Project - Not Recommended

This is not recommended as we are at risk of an unplanned SG outage or possible forced unit outage due to SG obsolescence and a lack of spare parts. Moreover, the REGM commitment would not be addressed and we would have to write approximately $ 5.4 M of capital charges off to OM&A

Alternative 1 - Proceed with Project - Recommended

Proceed with upgrades to the SG Governor system and related controls as outlined in section 4 below to reduce the increasing likelihood of an unplanned SG outage or forced unit outage. Because we cannot effectively install more than 3 governors this year, we will need to seek an extension to our REGM commitment and complete the final installation early in 2008. Completion of this work and the Protective Relay project will finalize the upgrades to the Pickering B Standby Generators and thereby remove the threat of a forced outage, maintain the Health System at white and satisfy a REGM commitment.

Due to the complexity of such an event (see Background Section), the likelihood of a forced outage due SG failure is not easily estimated. Lacking an accurate way to determine this level of risk, financial justification must be made on an assessment of whether there is a reasonable chance that the breakeven point for the incremental investment will be surpassed. Calculations indicate that the breakeven point is reached when the likelihood of a forced 30 day outage (involving 2 units) is 5.2% and the cost to repair is $300K. Based on past SG performance (see Attachment D), we feel it is reasonable to assume that we would likely surpass this level of risk, should the investment not be made. Moreover, it makes sense to complete the last major initiative of the $50M SG Upgrade program, so that we can realize the overall objective of SG reliability.

Alternative 2 - Delay Project - Not Recommended

This is not recommended as there is an increasing likelihood of an unplanned SG outage / forced unit outage and we would not be addressing the REGM commitment.

Alternative 3 – Install 2 of the remaining 4 - Not Recommended

Modifying only 2 of the remaining 4 Pickering B SG's is not recommended for the following reasons:

a) OPG is locked into an Engineered Material Vendor contract totaling all six SG's (as per previous release),
b) Increased likelihood of error when performing SG maintenance, as there would be two designs.
c) Increased documentation effort as all the operating and maintenance documentation would need to reflect two designs.
d) 68 percent of the project cost is with the first two SG's.

4/ THE PROPOSAL

We recommend continuing with the replacement of the existing SG Governor, sequencing/control relay logic, fuel delivery package and associated I&C monitoring for the remaining four Pickering B SGs.

Scope Breakdown:

Governor fuel delivery system replacement
New PLC based integrated governor and sequencer controls
Replace majority of the relay start/control logic with PLC
Independent over speed protection system (due to adoption of PLC)
Relay logic changes covered by Pratt & Whitney Study Report IMR 510
PLC based speed switches and timers
New Data event logger with expansion capabilities
New Machine monitor (temperature and vibration)

Phase II major project deliverables are as follows:

(a) Update Project Execution Plan
(b) Revise Vendor design packages as required
(c) Complete Design Packages for remaining two SG's (first four SG's completed under Phase I)
(d) Work Plans and Field Engineering Packages for remaining four SG's
(e) Systems and equipment installation and commissioning remaining four SG's
(f) New and/or revised Operating and Maintenance Procedures for remaining SG's.
(g) Project close out – station document updates, PASSPORT updates
(h) Post implementation review, lessons learned

The SG Governor Upgrade Project Execution Plan (PEP) NK30-PEP-54600-00001 defines the project scope to complete the deliverables. Finish dates in future based on current SG outage schedule. Should outages move, dates will vary accordingly.

5/ QUALITATIVE FACTORS

1. Lower system maintenance costs (Governor and logic failures being minimized) with the new Governor and start/control logic.
2. Improved diagnostic capabilities using new data logger and machine monitor, thus reducing forced SG outage troubleshooting times.
3. Elective and Corrective Maintenance backlogs expected to decrease due to replacement of instrumentation and components

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Additional material may be required depending on as found condition of machine when disassembled for the retrofit modification.	Added material costs to replace broken or unusable existing equipment.	**Medium**	Added $211K specific contingency for materials	**Low**
Increased OPG installation package preparation and design review costs due to Vendor documentation QA issues.	May not be able to complete installation packages within budget and schedule.	**Medium**	$209K Specific Contingency included for increased installation package preparation effort. OPG Supply Chain working with the Vendor to improve documentation QA through OPG corrective action process. Incorporating Lessons Learned.	**Low**
Scope				
May need to account for field discovery during installation phase.	Delay completion of tasks. May not be able to complete scope within allocated budget.	**Medium**	$499K Specific Contingency included for Installation to minimize impact. Design phase comprehensive walkdowns complete. Increase scope only with management approval and funding allocation. Incorporating Lessons Learned.	**Low**
Integration complexities with SG Upgrade project and other Maintenance.	Delay completion of tasks. May not be able to complete scope within allocated budget.	**Medium**	Specific Contingency included for Installation (see above) to minimize impact. Integrated work programs of SG Governor & SG Upgrade projects and station maintenance. Multiple station challenge reviews conducted. Incorporating Lessons Learned.	**Low**
Schedule				
REGM commitment for Dec07 at risk (aggressive station SG outage schedule).	Project may not meet current REGM deadline	**High**	REGM commitment date to be reviewed and extended as required.	**Low**
Station driven SG Outage	IOP process not being followed for	**High**	General contingency includes amounts for	**Medium**

schedule and SG outage maintenance window is very aggressive with little contingency. SG outage opportunities may change.	design issuance milestones and installation package preparation. Delay installation and SG return to service. May not be able to complete scope within allocated schedule windows and budget.		minor delays for the remaining 4 SG's. Many challenge reviews conducted to minimize hand-off / turn-over delays. Increased pre-outage preparation planning. Incorporating Lessons Learned. Recommend adding $2.8M to 2008 B.P. budget against final SG installation delays to 2008. To be reviewed during 2008 Business Planning. Risk remains medium.	
Delays caused by maintenance activities (unforeseen work) during SG outages could affect SG outage schedule	Delay installation. May not be able to complete scope within allocated budget.	**Medium**	Project integrated into station SG maintenance program. Added minor contingency to project schedule. Covered by Specific Installation Contingency discussed on previous page.	**Low**
Resources				
Limited engineering resources. Other project priorities.	Delay completion of scope. Impact on design schedule for subsequent SG's.	**Medium**	Use contract resources, if necessary.	**Low**
Limited installation resources (BTU and PWU). Competing with SG Upgrade project and other maintenance programs. Limited Ops resources during commissioning.	Delay installation	**Medium**	Use contract resources, if necessary. General contingency includes overheads to administer contracts. Pre-arranged Ops support including a SPOC prior to outage. Permit walkdown prior to outage.	**Low**
Engineered Material Vendor resources diverted to other contracts. Vendor has access to limited resources and has limited project management skills.	Delays in subsequent design packages for remaining SG's. Delays in testing and material delivery	**High**	OPG added resources to assist Vendor in project co-ordination. Vendor added technical and project management resources. Vendor advancing production schedule for remaining SG's. Supply Chain exploring other contractual remedies.	**Low**
Technical				
Commissioning / testing of complete modification on subsequent SGs. Possible software modifications during commissioning.	Delay return to service due to cumbersone SQA field change process. SG unavailability combined with other safety support system degradations (i.e., UPS, SES) may cause forced unit shutdowns.	**Medium**	Minor schedule and cost contingency added (see specific contingency on previous page). Design verifications, simulations and comprehensive FAT prior to installation. Independent verification of software and hardware design. Software Field Change process developed with Computer Design Group to enable parallel Software	**Low**

			verification with field implimentation. Incorporating Lessons Learned.	
Regulatory				
None.				
Environmental				
Scrapping of old material	Environmental regulatory non-compliance	**Medium**	Material to be sampled and scrapped in accordance with approved procedures.	**Low**
Health & Safety				
None.				
Investment				
Project does not satisfy the Business Objectives	Rework, extra cost	**Low**	The first two governors have been installed and are operating as designed	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jun 2008	Dec 2008	Director - Station Engineering

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Available For Service (first 2 SG's)	N/A	AFS and open items acceptance by stakeholders	Attach copy of AFS and open items with A/R's to PIR	System Engineer
2.	SG Machine performance Criteria Met	N/A	Commissioning results acceptance by Design	Signed Commissioning Report scanned in Passport	Project Manager
3.	Standby Generator (SG) System Health	Red	Removal of SG Governor and associated control systems as contributor to Red system status	Updated SG system health report indicating improved status for affected equipment	System Engineer
4.	REGM 28007285 complete	Dec 2007	SG Governor Project contribution to REGM completion	SMB REGM schedule review Milestone added to SG Outage Plan	Project Manager
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

AFS	Available for Service
BCS	Business Case Summary
B.P.	Business Plan
BTU	Builders Trade Union
COMS	Constructability, Operability, Maintainability, Safety
CUSW	Direct Hire Building Trade Union (Electrical)
CWP's	Comprehensive Work Packages
DCN	Design Change Notice
ECC	Engineering Change Control
EPG	Emergency Power Generator
FAT	Factory Acceptable Test
FE	Field Engineering
FIPR	Field Installation Package Release
FME	Foreign Material Exclusion
HFE	Human Factors Engineering
IOP	Integrated Operating Plan
ITP	Inspection Test Plan
I&C	Instrumentation and Controls
IRR	Internal Rate of Return
NUCORDS	Nuclear Components Reliability Data System
NPV	Net Present Value
OAR	Organizational Authority Register
OLW	Online Wiring
OM&A	Operations, Maintenance and Administrative expense
ONL	Online Wiring
OPEX	Operating Experience
Ops	Operations
O.T.	Overtime
PC1	Worker Protection Permit application Form
PEP	Project Execution Plan
PIR	Post Implementation Review
PFU	Predicted Unavailability Factor
PINO	Performance Improvement Nuclear Oversite
PLC	Programmable Logic Control
PSL	Power Supply List
PWU	Power Workers Union
QA	Quality Assurance
QCIV	Quality Control Inspection Verification
QSITP	Quality Surveillance Inspection Test Plan
REGM	SNSC Management Commitment
SCR	Site Condition Report
SE's	System Engineer
SES	Site Electrical System
SG	Standby Generator
SMB	Site Management Board
SPOC	Single Point of Contact
SQA	Software Qualification Assurance
TSSA	Technical Safety Standards Authority
UPS	Uninterruptible Power Supply

Appendix "B"

Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency)									
			Cumulative Values								
Release Type	Month	Year	2002	2003	2004	2005	2006	2007	2008	Later	Total
Developmental	Jul	2,002	300								300
Full (Phase 1)	Apr	2,004	87	0	1,010	7,712					8,809
Superseding	Feb	2,006	87	0	372	2,213	8,850	2,969	0		14,490
Full (Phase 2)	Jan	2,007	87	0	372	2,213	7,664	9,953	3,042		23,331
											0
											0
											0
											0

LTD Spent	Dec	2,006	87		372	2,213	7,664				10,336

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

Cost estimates have been verified by 3rd party reviewer, Atlas Helyar. Task Identification Sheets (N-Form-11025) have been validated by all contributing resource groups. Actuals and lessons learned have been incorporated into estimates.

Financial Assumptions:

The breakeven point for this investment is reached when the probability of a 2 unit forced outage of 30 days reaches 5.2% and the cost of repair accumulates to $300K. This is based on the following:

Loss of Revenue during forced unit outages:

(516MW for PB) X (85% Capacity Factor) X (24 Hours) X (30 Days) X (Rate MWH) X (2 Units).

Repair Costs during forced SG outages:

$300K per year + 3% inflation

Project / Station End of Life Assumptions:

Pickering B End of Life: 2014 Units 5, 6, and 7   2016 Unit 8

Energy Price / Production Assumptions:

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
56.2	58.2	57.0	55.6	54.4	54.2	56.3	60.2	64.4	67.1

Operating Cost Assumptions:
N/A

Other Assumptions:
N/A

Standby Generator Governor Upgrades Pickering B 13 - 49109 Capital 13 - 40528 OM&A

Full Release (Phase 2) Business Case Summary NK30-BCS-54600-00011-R000

Attachment "A" **Project Cost Summary**

$000's Capital & OM&A	LTD Prior Yr 2006	This Release 2007	This Release 2008					Later	Total
Project Management (OPG)	623	253	260	-					1,136
Engineering & Drafting (OPG)	1,874	1,018	374	-					3,266
Material	2,370	3,159	1,053						6,582
Installation – PWU, BTU	3,534	4,068	920						8,522
Contract - Design	495	57	4	-					556
Contract - Installation	386	264	86						736
Contract - Other	340	75	25	-					440
OMA Project 40528	459	-	-	-					459
									-
Interest (Capital Project Only)	255	249	74	-					578
Project Costs (excl contingency)	**10,336**	**9,143**	**2,796**	**-**	**-**	**-**	**-**	**-**	**22,275**
General Contingency		67	227						294
Specific Contingency		743	20						763
Project Costs (incl contingency)	**10,336**	**9,953**	**3,042**	**-**	**-**	**-**	**-**	**-**	**23,331**
2007-2011 Business Plan	10,336	7,083	2,230	-					19,649
Variance to Business Plan	**-**	**2,060**	**566**	**-**	**-**	**-**	**-**	**-**	**2,626**
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	**10,336**	**9,143**	**2,796**	**-**	**-**	**-**	**-**	**-**	**22,275**
Total Release (incl contingency)	**10,336**	**9,953**	**3,042**	**-**	**-**	**-**	**-**	**-**	**23,331**

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	100%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in place	Yes	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Apr 2007.

Reviewed By:

30 Jan 2007

George Makdessi
Project Manager

Date:

Approved By:

31 Jan 2007

Randy Ludlow
Eng & Mods Manager (Strat IV)

Date:

Standby Generator Governor Upgrades Pickering B 13 - 49109 Capital 13 - 40528 OM&A

Full Release (Phase 2) Business Case Summary NK30-BCS-54600-00011-R000

Attachment "B" **Project Variance Analysis**

Capital & OM&A	LTD Dec 2006	Total Project Last BCS Feb 2005	Total Project This BCS Jan 2007	Variance	Comments
Phase 1					
Project Management (OPG)	623	668	623	(45)	As per actuals
Engineering & Drafting (OPG)	1,874	1,518	2,039	521	Vendor software changes QA, Rework, Field Changes
Material	2,370	5,667	6,142	475	Commissioning Supp from Vendor, Increases to Misc Matl
Installation – PWU, BTU	3,534	3,654	3,735	81	As per actuals
Contract - Design	495	322	502	180	As above
Contract - Installation	386	260	392	132	056-SG3 Outage start delays, ES Fox/Crosby Dewar Increased Costs due to design changes.
Contract - Other	340	302	340	38	Training materials and hardware costs
OMA Project 40528	459	459	459	-	Sunk costs of previous OM&A project
Interest (Capital Project Only)	255	258	255	(3)	As per Actuals
Phase 1 (excluding contingency)	**10,336**	**13,108**	**14,486**	**1,378**	
General Contingency		**242**	-	(242)	Materialized risk as outlined in last BCS brought into budget.
Specific Contingency	-	1,140	-	(1,140)	Materialized risk as outlined in last BCS brought into budget
Phase 1 (incl contingency)	**10,336**	**14,490**	**14,486**	**(4)**	
Phase 2					
Project Management (OPG)	-	238	513	275	Outage Delays and increased support of Vendor
Engineering & Drafting (OPG)	-	450	1,227	777	Adjustments as per lessons learned and increased review effort of vendor design and field changes
Material	-	186	440	254	Commissioning Support from Vendor, Increased Misc Matl costs (lessons learned)
Installation – PWU, BTU	-	4,650	4,787	137	Adjustments as per lessons learned
Contract - Design	-	49	55	6	Adjustments as per lessons learned
Contract - Installation	-	393	344	(49)	Adjustments as per lessons learned
Contract - Other	-	100	100	-	
OMA Project 40528	-	-	-	-	
Interest (Capital Project Only)	-	174	323	149	Cash Flow adjustments
Phase 2 (excluding contingency)	**-**	**6,240**	**7,789**	**1,549**	
General Contingency		**1,409**	**86**	(1,323)	Incorporation of lessons learned.
Specific Contingency		-	970	970	Identified risks going forward
Phase 2 (incl contingency)	**-**	**7,649**	**8,845**	**1,196**	
Total Project (incl contingency)	**10,336**	**22,139**	**23,331**	**1,192**	
General Contingency		**1,651**	**86**		
Specific Contingency		**1,140**	**970**		
Total Project (excl contingency)	**10,336**	**19,348**	**22,275**	**2,927**	

Comments:

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
15	Apr	2007	Revise PEP
09	Feb	2007	5th SG Detailed Design Package 056SG2
07	May	2007	6th SG Detailed Design Package 078SG2
19	Feb	2007	056-SG1 (3rd SG) Installation Start (T-0)
07	May	2007	078-SG1 (4th SG) Installation Start (T-0)
22	Oct	2007	056-SG2 (5th SG) Installation Start (T-0)
15	Feb	2008	078-SG2 (6th SG) Installation Start (T-0)
10	Apr	2007	056-SG1 (3rd SG) AFS
06	Jul	2007	078-SG1 (4th SG) AFS
21	Dec	2007	056-SG2 (5th SG) AFS
7	Apr	2008	078-SG2 (6th SG) AFS
30	Dec	2008	Project Complete

A Project Execution Plan (PEP) will be approved by 2007

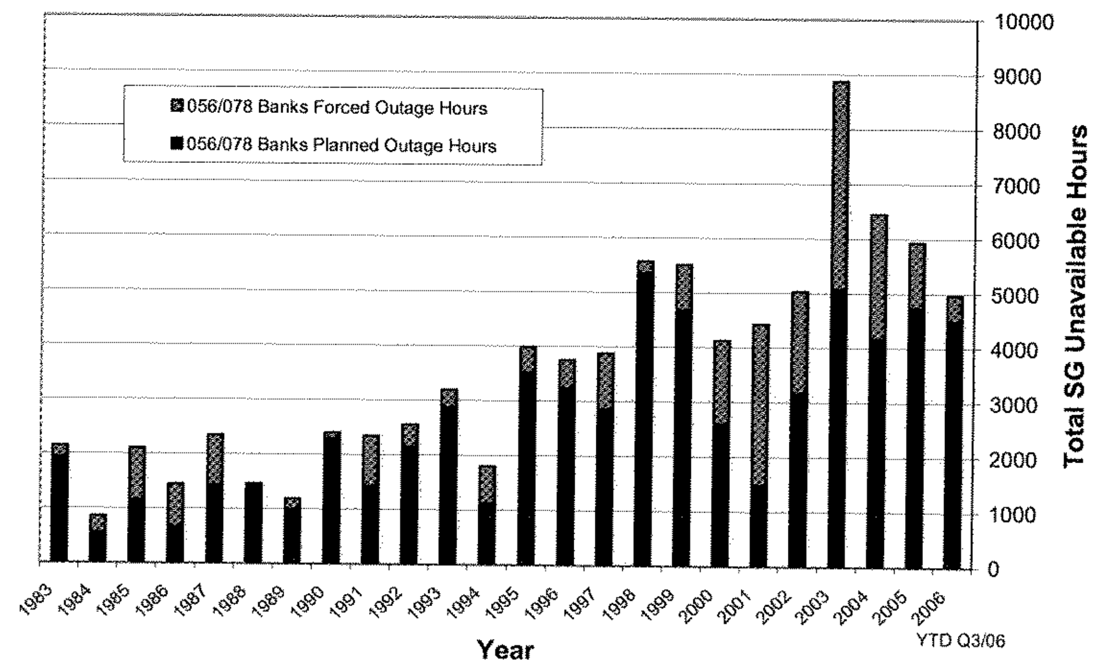
Comments:

Attachment 'D'

Pickering B Standby Generator 2005 & 2006 Failures / SCR Summary

Functional Failures (QTR/2YR)	Common		056 SGs		078 SGs		Overall System Health
	Qtr	2 Yr	Qtr	2 Yr	Qtr	2 Yr	
Q1 2005	0 →	0	0 ↓	9 ↓	2 ↑	17 →	RED
Q3 2005	0 →	0	1 ↓	6 ↓	1 ↓	16 ↓	RED
Q2 2005	0 →	0	2 ↓	6 ↓	2 ↓	16 ↓	RED
Q4 2005	0 →	0	0 ↓	6 →	1 →	16 →	RED
Q1 2006	0 →	0 →	0 ↓	4 ↓	0 →	14 ↓	RED
Q2 and Q3 2006	0 →	0 →	0 ↓	4 ↓	0 →	14 ↓	YELLOW
Q4 2006	0 →	0 →	0 →	1 ↓	0 →	7 ↓	WHITE

Pickering B SG Unavailable Hours per Year (Planned vs Forced/Outage Extension)



Event Date	SCR	Equipment / Event Summary
Jan 04, 2005	P-2005-00131	056-54600-SG3 tripped during start-up of pre-outage test run on "PT Exhaust Temp.
Jan 18, 2005	P-2005-01151	078-54600-SG2 tripped during start-up of routine P-07 test run.
Feb 13, 2005	P-2005-02699	078-54600-SG2 tripped on "DC Lube Oil Pump Failure" during U7 P-05 routine test - defective pressure switch PS12.
Feb 18, 2005	P-2005-03115	056-54600-SG1 incurred a "Fuel Boost Pressure Low" (Test Mode only) start trip during U5 loss of class III bus test. It is a Peaking Mode only trip.
Feb 19, 2005	P-2005-03249	078-54600-SG3 failed to start and was rejected duringU7 P-5 test. Fault was traced back to a faulty T8 timer.
Mar 18, 2005	P-2005-05152	056-54600-SG3 tripped on "PT Exhaust Temp. High" during start-up of U6 UPSB backup test.
May 01, 2005	P-2005-07961	056-54600-SG1 tripped during start-up of P7 routine test run on "PT Lube Oil Sequence Failed". – It is a Peaking Mode only trip. Intermittent equipment failure.
May 22 , 2005	P-2005-09305	078-54600-SG3 tripped during start-up of routine P-07 test run on "Main Lube Pressure Low" - defective T8 timer.
Jun 18, 2005	P-2005-10865	056-54600-SG2 tripped on "PT Lube Oil Sequence Failed" during P7 routine test. It is a Peaking Mode only trip. Defective T11 timer.
Jun 28, 2005	P-2005-11400	078-54600-SG3 tripped during start-up of routine P-07 test run on "Main Lube Pressure Low". – Defective T8 timer.
Jul 05, 2005	P-2005-11683	078-54600-SG2 failed to start.
Jul 06, 2005	P-2005-11734	Temperature Switch Non-Conformance.
Jul 07, 2005	P-2005-11779	Actual Past Unavailability due to SGs Failures
Aug28, 2005	P-2005-14142	056-54600-SG3 Unavailable.
Sep 19, 2005	P-2005-15563	Fuel leak at 056-SG3 fuel oil integrator FZ3399
Nov 22, 2005	P-2005-19625	078-54600-SG3 tripped during start up for routine test.
April 20, 2006	P-2006-06624	078 SG2 trip on startup. 078-SG2 started for supporting Unit 8 BUS transfer operation @ 10:52 on April 20/06. The machine tripped approximately 15 seconds into the start sequence. DC Lube Oil pump did not start as expected. Trip appears to be spurious.
Sept. 30, 2006	P-2006-16975	On 09/30/06 @ 4:00, CI 525 "056-SG1 Process Trouble" annunciated in MCR. Local inspection discovered "FIRE" window lit on. SG was declared unavailable (ref. SCR P-2006-16975 & WR# 520871). Fault was traced back to a defective R1 relay which caused this spurious alarm.
Dec 18, 2006	P-2006-24708	Standby Generation Impairment 078-SG1 tripped on routine test run./ During routine P-007 test run of 078-SG1on Dec 18/06, the machine started up with an initial frequency @ 63 Hz which was above the normal 61.2 Hz.

Darlington Phase II Fire Protection Project 16 - 79016

Superseding Business Case D-BCS-78000-10003-R000

1/ RECOMMENDATION:

Approval is requested for this Superseding release for ~~18.873M$~~ $ 19.058 Million, including all Capital costs. $ 185k will be written off to OM&A as discussed below. Capital, to:

- Remove Turbine-Generator Dyking from scope as it has been deemed unnecessary by engineering review, and which would drive costs further beyond the previously released amount for this project,
- Write-off the costs incurred against the scope of work for removal ($185K), and
- Approval for an over-variance to release of $127K (including contingency), to complete close-out of this Capital project,

Relevant.

The business objectives of the Darlington Phase II Fire Protection Project were as follows:

1. Install Turbine-Generator Fire Suppression Upgrades (REGC).
2. Install Fire Detection Upgrades in the Main Control Room & associated areas (REGC).
3. Construct an Emergency Response Team (ERT) Facility (CNO Commitment).
4. Install Containment Dyking around each Turbine-Generator set.

The project is now 98% complete. The REGC and CNO commitments were met in 2002. All work on the Detection Upgrades and the ERT Facility is complete, including ECC closeout. With T-G Dyking removed from scope, the outstanding work for this project includes:

- Available For Service (AFS) activities and ECC closeout for the Suppression Upgrades,
- Project Closeout activities, including Post-Implementation Review.

Recommended for scope removal is the Turbine-Generator Oil Containment Dyking modification. An engineering assessment concluded that the intent of containment dykes (to prevent the spread of burning lube oil) is already met. Removal of this work from scope will mitigate the need for an additional $500K funding. To date, $185K has been spent in the design phase for this modification and this money should be written off to OM&A.

The cost over-variance for this project is attributed to the following:

- Discovery work & additional scope for the fire suppression upgrades: install new pressure relief devices and reroute piping due to equipment interferences.
- Rework to change the ERT Facility modification from a Commercial Mod (CMOD) to a combination Permanent Mod (PMOD) and Facility Mod (FMOD).

$000's (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	Superseding	18,412	306	28					**18,746**
Requested Now	Superseding			258	54				**312**
Future Funding Req'd									-
Total Project Costs		**18,412**	**306**	**286**	**54**	-	-	-	**19,058**
Other Costs	Write Off			(185)					**(185)**
Ongoing Costs									-
Grand Total		**18,412**	**306**	**101**	**54**	-	-	-	**18,873**

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Regulatory	Capital	N/A	N/A	N/A

Submitted By:

Wayne Robbins 2007-08-15

Name: W. Robbins Date:

Title: Senior Vice President - Darlington Nuclear

Finance Approval:

Sept 27/07

Name: J. Beech Date:

Title: Vice President - Nuclear Finance

Line Approval (Per OAR Element 1.4 Variance):

10/10/2007

Name: T. Mitchell Date:

Title: Chief Nuclear Officer

2/ BACKGROUND & ISSUES

The Superseding Business Case Summary for this project, D-BCS-78000-10002 R000, was approved on September 12, 2002 for $18.7M, including contingency. The project scope is as follows:

1) Install a Turbine-Generator Fire Suppression System. This was a CNSC Regulatory Commitment, AR #28023793.
2) Install a containment barrier around each Turbine-Generator set to control the flow of potentially burning lube oil and fire water. This modification is per a requirement in OPG Standard N-STM-78200-10000-R01, Fire Protection for Turbine Generator Areas
3) Install Fire Detection upgrades in the MCR, CER & associated areas. This was a CNSC Regulatory Commitment, AR #28023789.
4) Construct an Emergency Response Team (ERT) Facility. This was a CNO commitment.

Current Status:

- The REGC and CNO commitments were met in 2002.
- All Fire Detection Upgrades (item 3 above) are complete. The modification has been closed and there are no open items.
- The ERT Facility (item 4 above) is complete. The modification has been closed and there are no open items.
- The T-G Fire Suppression System installation (item 1 above), to meet the REGC is complete and Final AFS was obtained. However, during the Post-AFS period, the following issues were identified:
    1) Lack of required pressure relief capability in the suppression system (SCR D-2004-08302)
    2) Piping interference with adjacent equipment, preventing maintenance activities from being performed (SCR D-2004-05603)

  As a result, the Final AFS was changed to a Partial AFS, to allow for resolution of these issues. This did not affect meeting the REGC. The field work to resolve these issues is complete, and Final AFS is pending.
- The need for T-G Dyking (item 2 above) has been challenged. An engineering assessment has been performed (see NK38-REP-78000-10004), concluding that the intent of containment dykes, to control the spread of burning lube oil and fire water, is already met via the physical layout of the station, and fire suppression capability in place. Removal of this work from scope will mitigate the need for an additional $500K funding.

Over-Variance Contributors:

- ERT Facility

  The ERT Facility was originally constructed as a commercial modification (CMOD). However, this was not accepted at the time of turn over (reference SCR-D-2003-02188). To obtain final acceptance, the CMOD was converted to a combination of facility modification (FMOD) and permanent modification (PMOD) (reference NK38-REP-28600-10002). The re-engineering to do this conversion, the cost for building maintenance until Final AFS, and the resulting impact on the project schedule, contributed to the over-variance for this project. Final AFS has been obtained and all work with the ERT Facility has been completed. There are no open items & it has been closed out.
- T-G Suppression Pressure Relief & Piping Interference Issues

  Resolution of the two T-G Suppression issues required DCP revision, re-design, additional field work, troubleshooting, AFS activities, and an overall extension to the project schedule.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3 Do Less	Alt 4 Do More	Alt 5 N/A
Revenue	-	-	-	-	-	-	
OM&A	-	-	-	-	-	-	
Capital	19,538	19,038	(500)		N/A	N/A	
NPV (after tax)							
Impact on Economic Value (IEV)	N/A						
IRR%	N/A						
Discounted Payback (Yrs)	N/A						

Status Quo - Not Recommended

The status quo for this project would include installation of T-G Dyking and would cost approximately $500K in addition to the current over-variance requested. A recent engineering review demonstrated that the intent of T-G Dyking is already met through existing suppression & the physical layout of the station. This is a Non-Value-Enhancing project, and significant effort has been put forth to reduce scope where possible. The Regulatory and Management commitments have been met. This option is not recommended.

Alternative 1 - Complete AFS and Close-Out - Recommended

The project is now 98% complete. It is recommended that T-G Dyking be removed from scope, and proceed with AFS & closeout activities for the remainder of the project. This requires an over-variance to release approval of $127K (less than 1% increase on the current release of $18.746M). To date, $185K has been spent in the design phase for T-G Dyking and this money should be written off to OM&A.

Alternative 2 - Delay Project - Not Recommended

Delaying is not recommended as this project is in the Closeout Phase and closeout activities must continue per ECC governance. Delaying the installation of T-G Dykes only is also not recommended as it is a non-value-enhancing modification that has been deemed redundant through engineering review.

Alternative 3 – Do Less - Not Recommended

With T-G Dyking removed from scope, there are no further opportunities to do less as the remaining scope is either in closeout phase, or already closed out.

Alternative 4 – Do More - Not Recommended

This is a Non-Value-Enhancing project, and significant effort has been put forth to reduce scope where possible. The Regulatory and Management commitments have been met.

Alternative 5 – N/A - Not Recommended

4/ THE PROPOSAL

1) Remove T-G Dyking from the scope of this project
2) Write-off $185K to OM&A; the costs incurred to date for the T-G Dyke design
3) Approve $127K over-variance to release for the completion of this project. Specifically:
    - AFS activities for T-G Sprinkler mods
    - Closeout activities for T-G Sprinkler mods
    - Project Closeout activities

5/ QUALITATIVE FACTORS

The drivers for these modifications were Regulatory & CNO Commitments aimed at improving the level of personnel and asset protection from fire. At the current stage for this project, Closeout, the qualitative factor for continuing is compliance with ECC governance.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Risk of cost increase is low as the project is in Final AFS & Closeout. Cost to complete is well defined.	N/A	**Low**	N/A	**Low**
Scope				
Risk of new scope being added to the project is low as the project is in Final AFS & Closeout. All additional scope items were identified at previous AFS..	N/A	**Low**	N/A	**Low**
T-G Dyking not removed from scope.	Project will incur approximate additional $500K in cost and schedule extension	**Medium**	Engineering evaluation performed to show T-G Dyking not required. Approval of this BCS will reduce the risk to low.	**Low**
Station does not accept state of passing RVs in field	Maintenance work required to fix or replace RVs prior to AFS.	**Medium**	Independent Third Party Review obtained states passing RV is code compliant. Field walkdowns with station representatives to obtain acceptance.	**Low**
Schedule				
Maintenance work required to fix or replace RV's prior to AFS.	Missed AFS milestone	**Medium**	Independent Third Party Review obtained states passing RV is code compliant. Field walkdowns with station representatives to obtain acceptance.	**Low**
Resources				
Insufficient Design resources to complete closeout.	Missed Closeout milestone and ECC Action Tracking Assignments	**Medium**	Commitments have been obtained from Design and Drawing Office to complete outstanding work	**Low**

Technical				
N/A - all technical issues identified at previous AFS				
Regulatory				
N/A all Regulatory commitments have been met				
Environmental				
N/A as this remaining work has no environmental risk.				
Health & Safety				
N/A as there is no remaining field work.				
Investment				
N/A as there is no remaining field work.				

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Aug 2007	Mar 2008	Manager, Performance Engineering

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Project Objectives have been met			Review of Charter, PEP, BCS's	Manager, Performance Engineering
2.					
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

AFS – Available For Service
CER – Control Equipment Room
CNO – Chief Nuclear Officer
ECC – Engineering Change Control
ERT – Emergency Response Team
MCR - Main Control Room
REGC – Regulatory Commitment
SCR – Station Condition Record
T-G – Turbine-Generator

Appendix "B"

Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2006	2007	2008	2009	2010	2011	2012	Later	Total
Full	Aug	2002	18,718	28							18,746
Superseding	Jun	2007	18,718	101	54						18,873
											0
											0
											0
											0
											0
											0

LTD Spent	May	2007	18,737								18,737

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

- T-G Dyking will be removed from the scope of this project

Financial Assumptions:

N/A

Project / Station End of Life Assumptions:

N/A

Energy Price / Production Assumptions:

N/A

Operating Cost Assumptions:

N/A

Other Assumptions:

Phase II Fire Protection Project 16 - 79016

Superseding Business Case D-BCS-78000-10003-R000

Attachment "A" **Project Cost Summary**

Choose One Choose One	LTD Prior Yr 2006	This Release 2007	This Release 2008	This Release 2009				Later	Total
Project Management (OPG)	2,347	148	42	-					2,537
Engineering & Drafting (OPG)	1,309	48	5	-					1,362
Material	1,263	-	-	-					1,263
Installation – PWU, BTU	4,731	10	-	-					4,741
Contract - Design	4,471	11	-	-					4,482
Contract - Installation	3,107	-	-	-					3,107
Contract - Other	-	-	-	-					-
									-
									-
Interest (Capital Project Only)	1,490	32	-	-					1,522
Project Costs (excl contingency)	**18,718**	**249**	**47**	**-**	**-**	**-**	**-**	**-**	**19,014**
General Contingency		37	7	-					44
Specific Contingency		-	-	-					-
Project Costs (incl contingency)	**18,718**	**286**	**54**	**-**	**-**	**-**	**-**	**-**	**19,058**
2007-2011 Business Plan	18,718	33	-	-					18,751
Variance to Business Plan	**-**	**216**	**47**	**-**	**-**	**-**	**-**	**-**	**263**
Committed Cost		-	-	-					-
Inventory Write Off Required		(185)	-	-					(185)
Spare Parts / Inventory		-	-	-					-
Total Release (excl contingency)	**18,718**	**64**	**47**	**-**	**-**	**-**	**-**	**-**	**18,829**
Total Release (incl contingency)	**18,718**	**101**	**54**	**-**	**-**	**-**	**-**	**-**	**18,873**
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	100%		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	N/A	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	N/A	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF will be approved by Jul 2007.

Reviewed By: 4 July 2007

Tom Ovitkovic
Project Manager

Date:

Approved By: 12 July 2007

Terry Chong
Eng & Mods Manager (Strat IV)

Date:

Project Name 16 - 79016

Superseding Business Case D-BCS-78000-10003-R000

Attachment "B"

Project Variance Analysis

Capital	LTD May 2007	Full Release		Variance	Comments
		Last BCS Sep ~~Choose~~ 2002	This BCS Jun 2007		
Project Management (OPG)	2,350	1559	2537	978	
Engineering & Drafting (OPG)	1309	1855	1362	-493	
Material	1,263	0	1263	1263	Mat'l cost included in Installation
Installation – PWU, BTU	4731	5709	4741	-968	for previous BCS
Contract - Design	4471	3884	4482	598	Design/Build contract estimates
Contract - Installation	3104	3884	3107	-777	combined for previous BCS
Contract - Other	0	0	0	0	
				0	
				0	
Interest (Capital Project Only)	1,509	887	1522	635	
Project Costs (excl contingency)	**18737**	**17778**	**19014**	**1236**	
General Contingency		**400**	**44**	-356	
Specific Contingency		569	0	-569	
Project Costs (incl contingency)	**18737**	**18747**	**19058**	**311**	
Committed Cost			0	0	
Inventory Write Off Required			-185	-185	Write-Off T/G Dyking Design
Spare Parts / Inventory			0	0	
Total Release (incl contingency)	**18737**	**18747**	**18873**	**126**	
Total Release (excl contingency)	**18737**	**17778**	**18829**	**1051**	

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
10	Aug	2007	RV Installation AFS
10	Jul	2008	Project Closeout

A Project Execution Plan (PEP) was approved in MAY 1999 ~~$~~ 07-04-07

Comments:

Additional Feeder Cut and Weld Tooling 10 - 62567

Full Release Business Case Summary N-BCS-30320-10003-R000

1/ RECOMMENDATION:

We recommend approval of a full release of $15.8M to purchase 3 additional and complete sets of Cut and Weld Tools for feeder replacement. Based on lessons learned during the first usage of Cut and Weld equipment in the D611 outage, we recommend supplementing these additional sets with some new minor tools as well as incorporating some design improvements. Ownership and usage of the tools sets will be controlled under the same Cut and Weld agreements we currently have with AECL, B&W, and Bruce Power.

The Business Objective of this project is to generate additional revenue by reducing the length of outages in the 2008 to 2017 time frame by using the recommended new Cut and Weld tooling.

We estimate feeder replacement to be the critical path item for all Pickering A and Darlington outages in the 2008-2017 timeframe. The 3 sets of tools will make the following currently unachievable results possible:

- Conducting feeder replacement execution at 2 reactor faces in parallel when it is required.
- Completing concurrent training or one face execution at another Nuclear station, if it is required
- Reducing feeder replacement time by using the new and improved tools

DNGS has indicated the requirement for additional tooling to perform a concurrent 2-face campaign. We estimate that similar conditions can be expected regularly at both PNGSA and DNGS in the 2008-2017 timeframe. Additionally, outage delays are possible, if there is a shortage of tools due to an overlap in feeder replacement campaigns for OPG and Bruce Power stations.

We estimate that, between 2008 and 2017, we can generate additional revenue of approximately $69.6 Million by using the new tool sets to reduce feeder replacement times and to mitigate the risk of outage delays due to tooling shortages. The NPV of this $15.8M capital investment is estimated to be $21M with an IRR of 40.5% and a discounted payback of 4.3 years.

A Full Release is required to make commitments to the supplier that will ensure tool availability by D811.

$000's (incl contingency)	Funding	LTD 2005	2006	2007	2008	2009	2010	Later	Total
Currently Released	N/A								-
Requested Now	Full			4,990	9,289	1,484			15,763
Future Funding Req'd									-
Total Project Costs		-	-	4,990	9,289	1,484	-	-	15,763
Other Costs									-
Ongoing Costs									-
Grand Total		-	-	4,990	9,289	1,484	-	-	15,763
Investment Type Sustaining		Class Capital		(IEV) Impact on Ec Value 21.0		IRR 40.5%		Discounted Payback 4.3	

Submitted By:

(see attached)

P. Spekkens
Vice President
Science & Technology Development

Date:

Finance Approval:

July 12/07

D. Power
V.P. Corporate Investment Planning

Date:

T. Halady July 12/07

Line Approval (Per OAR Element 1.2 Project not in Budget):

July 13/07

J. Hankinson
President & CEO

Date:

Additional Feeder Cut and Weld Tooling 10 - 62567

Full Release Business Case Summary N-BCS-30320-10003-R000

1/ RECOMMENDATION:

We recommend approval of a full release of $15.8M to purchase 3 additional and complete sets of Cut and Weld Tools for feeder replacement. Based on lessons learned during the first usage of Cut and Weld equipment in the D611 outage, we recommend supplementing these additional sets with some new minor tools as well as incorporating some design improvements. Ownership and usage of the tools sets will be controlled under the same Cut and Weld agreements we currently have with AECL, B&W, and Bruce Power.

The Business Objective of this project is to generate additional revenue by reducing the length of outages in the 2008 to 2017 time frame by using the recommended new Cut and Weld tooling.

We estimate feeder replacement to be the critical path item for all Pickering A and Darlington outages in the 2008-2017 timeframe. The 3 sets of tools will make the following currently unachievable results possible:

- Conducting feeder replacement execution at 2 reactor faces in parallel when it is required.
- Completing concurrent training or one face execution at another Nuclear station, if it is required
- Reducing feeder replacement time by using the new and improved tools

DNGS has indicated the requirement for additional tooling to perform a concurrent 2-face campaign. We estimate that similar conditions can be expected regularly at both PNGSA and DNGS in the 2008-2017 timeframe. Additionally, outage delays are possible, if there is a shortage of tools due to an overlap in feeder replacement campaigns for OPG and Bruce Power stations.

We estimate that, between 2008 and 2017, we can generate additional revenue of approximately $69.6 Million by using the new tool sets to reduce feeder replacement times and to mitigate the risk of outage delays due to tooling shortages. The NPV of this $15.8M capital investment is estimated to be $21M with an IRR of 40.5% and a discounted payback of 4.3 years.

A Full Release is required to make commitments to the supplier that will ensure tool availability by D811.

Currently Released	N/A								-
Requested Now	Full			4,990	9,289	1,484			15,763
Future Funding Req'd									-
Total Project Costs		-	-	4,990	9,289	1,484	-	-	15,763
Other Costs									-
Ongoing Costs									-
Grand Total		-	-	4,990	9,289	1,484	-	-	15,763

Submitted By:

Paul Spekkens June 28, '07

P. Spekkens
Vice President
Science & Technology Development

Date:

Finance Approval:

D. Power
V.P. Corporate Investment Planning

Date:

Line Approval (Per OAR Element 1.2 Project not in Budget):

J. Hankinson
President & CEO

Date:

2/ BACKGROUND & ISSUES

The integrity of CANDU primary heat transport piping, which connects the header to the nuclear reactor's fuel channels, referred to as "feeder tubes", has become an issue as a result of two degradation mechanisms; thinning caused by flow accelerated corrosion, and feeder pipe wall cracking, which is believed to be caused by stress related corrosion or low temperature pipe elongation creep. OPG addressed these feeder degradation issues via the Feeder Integrity Project (FIP), which included a number of sub-projects. To address station concerns on feeder thinning, the FIP Cut and Weld sub-project, partnering with a similar team at Bruce Power, managed the development and acquisition of a set of advanced tooling to repair thinned sections of feeder tubing positioned beyond arms reach.

The Advanced Cut and Weld tooling for feeder replacement developed under the original scope (Project #10-33993) has been successfully used during the D611 Outage. Three sets of tooling were obtained, one for face use, one for back-up and a third for training. Following the first use of this one of a kind tooling in the D611 Outage, OPEX identified areas for performance improvements. Additional funding was subsequently released under Project #10-62562 to cover the improvements considered essential for P711 and D721 Outages. However, the existing tooling continues to be limited to feeder replacement at 1 face, 1 station due to the number of tool sets.

Since there has been only one feeder replacement outage, the reliability of the tooling has not been seriously tested, although there have been difficulties in getting some tools out of the station due to contamination. It is highly likely that there'll be attrition loss or contamination of tools as more feeder replacement campaigns are executed. In addition, Darlington has indicated the needs to execute feeder replacement concurrently on the two reactor faces starting in the D811 outage and then on a regular basis until 2017. Pickering A is expected to have the same requirement starting in the P911 outage. Analysis indicates this requirement will add 36 days to Darlington outages and 16 days to PNGS-A outages in the period from 2008 to 2017.

Furthermore, outage delays are possible, if there is a shortage of tools due to an overlap in feeder replacement campaigns for OPG and Bruce Power stations. Outage organizations are trying to maintain a 2-week gap between the outages of different stations (PA, PB and DA); however, there is a reasonable probability that this scheduling will not be maintained. An additional 3 sets of tooling will mitigate the risk of an outage delay due tool shortages.

We estimate that, between 2008 and 2017, we can generate additional revenue of approximately $69.6 Million by using the new tool sets to reduce feeder replacement times and to mitigate the risk of outage delays due to tooling shortages.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ Millions	No Project	Alt 1 (Recommended) Full Cost 3 Tools in '08 Bruce 0% No-ROW	Alt 1 (Recommended) Incr Cost 3 Tools in '08 Bruce 0% No-ROW	Alt 3 Training Set '08 3 Tools in '09 Bruce 40% A-ROW incl	Alt 4 3 Tools in '08 Bruce 40% A-ROW Included	Alt 5 1 Tool in '08 Bruce 0% No A-ROW	
Revenue	(69.6)			(5.0)		(25.0)	
OM&A							
Capital		(15.8)	(15.8)	(14.4)	(12.8)	(10.0)	
NPV (after tax)	(32.0)	(11.0)	(11.0)	(12.9)	(9.0)	(18.6)	
Impact on Economic Value (IEV)	N/A	21.0	21.0	19.1	23.1	13.4	
IRR%	N/A	40.5%	40.5%	N/A	N/A	N/A	
Discounted Payback (Yrs)	N/A	4.3	4.3	N/A	N/A	N/A	

Status Quo - Not Recommended

We do not recommend this alternative because there is a more economic way to complete feeder replacements by using additional and enhanced Cut and Weld tooling collectively purchased and controlled under the same Cut and Weld agreements we currently have with AECL, B&W, and Bruce Power.

Alternative 1 - Purchase 3 Sets of Tools with NO A-ROW & NO Bruce Participation - Recommended

We recommend this alternative because we estimate that, between 2008 and 2017, we can generate additional revenue of approximately $69.6 Million by using 3 additional and enhanced tool sets to provide tooling capability for concurrent feeder replacement campaigns, and to mitigate the risk of outage delays due to tooling shortages. The NPV of this $15.8M capital investment is estimated to be $21M with an IRR of 40.5% and a discounted payback of 4.3 years.

Alternative 2 - Delay Project - Not Recommended

We do not recommend delaying the recommendation because the opportunity to generate more revenue is greater than the savings that can be derived from a delay.

Alternative 3 – Upgrade Training Set for D811, 3 Sets with A-ROW / Bruce for '09 - Not Recommended

We do not recommend this alternative because the extra cost of the tools ($1.6M) when compared the similar alternative (Alt 4) and the lost opportunity to generate more revenue ($5.0M) make this alternative financially less acceptable ($1.8M) than the recommendation.

Alternative 4 – 3 Sets of Tools with A-ROW & Bruce Participation - Not Recommended

We do not recommend at this time as the Bruce Power participation has not been confirmed. If Bruce Power is confirmed at a later date, this alternative will be considered and there'll be an approx. $3M saving to OPG. The trade off is that Bruce Power will share the tools with OPG, but this was the agreement on the original sets of tools. Exclusive ownership of the additional tools by OPG makes the existing tools more readily available to Bruce Power, resulting in effective sharing of all the tools.

Alternative 5 – Purchase 1 Set of Tools with A-ROW & Bruce Participation - Not Recommended

We do not recommend this alternative because the lost opportunity to generate additional revenue ($25M) by using the new tool sets to mitigate the risk outage delays make it financially less acceptable ($7.6M NPV) than the Recommendation.

4/ THE PROPOSAL

External contractors AECL and B&W will be utilized, in keeping with AGREEMENT No. OPG/BP-01, July 15, 2004. Additional external welding equipment expertise will be utilized to ensure tooling improvements are warranted and proposals are sound. Base organizations will provide 1 FTE plus 1 augmented FTE's to support the assessment, specification, development and purchase of the new tool sets.

The scope of the Improved Cut and Weld Tooling project is as follows:

a. **Assess Needs and Improvement Opportunities.** Obtain information from each station to determine the requirements for concurrent 2 face campaigns and risks of overlapping outages. Review OPEX and lessons learned on use of the tooling in Fall 2006 outage at Darlington (D611) and develop recommendations for improvements.

b. **Purchase the additional Tooling.** Complete the required documentation for specification and purchase of the required tooling.

c. **Monitor the development and supply of tooling.** Provide oversight to ensure tooling development meets the improvement and delivery schedule requirements.

5/ QUALITATIVE FACTORS

An increase in tooling efficiency will reduce worker dose uptake and lower risk of injury.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Price increase from vendor budgetary quote to firm quote	Cost overrun	**Medium**	Obtain updated budgetary quote. 9% contingency in place.	**Low**
Bruce Power does not participate	Cost overrun	**Medium**	Early identification of Bruce Power interest through negotiations. They have expressed interest in the option recommended in this BCS and a letter of intent is expected soon.	**Low**
Scope				
Discovery issues require additional scope	Cost overrun and schedule delay	**Medium**	Increased scope to be addressed using Change Management Process (CPM), PM principles, and/or a superseding BCS	**Low**
Schedule				
Delayed award of contract affects training and tooling delivery for D811 Outage	Outage critical path extension.	**High**	Increased effort on the BCS process and contract negotiations.	**Medium**
Resources				
Lack of experienced engineering support resources for this project	Schedule delay	**Medium**	Plan to use qualified contractor resources. High level of management oversight to track contractor performance.	**Low**
Technical				
Technical issues results in less than satisfactory tooling improvements or new tools	Not all the benefits can be realized	**Medium**	Mock-up testing/training to prove tooling effectiveness. High level of management oversight to track contractor performance	**Low**

BUSINESS CASE SUMMARY

Regulatory				
Environmental				
Health & Safety				
Investment				

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	**Jun 2009**	**Dec 2009**	**Manager, Feeder Integrity Projects**

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Feeder replacement execution on 2 reactor faces in parallel	Work in series between reactor faces.	Work concurrently on 2 reactor faces if required. No project execution delays due to tooling shortage.	OPEX from post outage lessons learned.	Manager, Feeder Integrity Projects
2.	Availability of additional feeder Cut & Weld Tooling for training or execution at another station	Not available	No delays in training or feeder replacement (one face) due to tooling at another station.	OPEX from outages where feeder repacement overlaps at two nuclear stations.	Manager, Feeder Integrity Projects
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

technical terms explanation embedded in the BCS

Appendix "B" **Project Funding History**

$ 000's		All Existing and Planned Releases (incl contingency)									
			Cumulative Values								
Release Type	Month	Year	2007	2008	2009	2010	2011	2012	2013	Later	Total
Full	Jun	2,007	4,990	9,289	1,484						15,763
											0
											0
											0
											0
											0
											0
											0

LTD Spent											0

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

Tool Cost based on Budgetary Quote from AECL and B&W.

Financial Assumptions:

7% WACC

Project / Station End of Life Assumptions:

DNGS 2017
PNGS-A 2023
PNGS-B 2014

Energy Price / Production Assumptions:

49.50 MWH plus 2% starting in 2009

Operating Cost Assumptions:

Estimated number of outage extension days potentially saved when work on 2 reactor faces in parallel is:

# days	2008	2009	2010	2011	2014	2015	2017
PNGSA		2.5	8.3	5.4			
DNGS	5	3.3		6.3	9.4	5	7.2

Other Assumptions:

We are estimating that there is a 10% probability of a $25M outage extension per year due to a tool shortage from conflicting outages among Pick A, B, Darlington and Bruce Power stations in the years 2008 -2017

Additional Feeder Cut and Weld Tooling 10 - 62567

Full Release Business Case Summary N-BCS-30320-10003-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2007	This Release 2007	Future Release 2008	2009	2010	2011	2012	Later	Total
Project Management (OPG)		10	180	90					280
Engineering & Drafting (OPG)		20	270	140					430
Material		4,500	7,720						12,220
Installation – PWU, BTU									-
Contract - Design									-
Contract - Installation									-
Contract - Other									-
	-								-
									-
Interest (Capital Project Only)			299	1,174					1,474
Project Costs (excl contingency)	-	4,530	8,469	1,404	-	-	-	-	14,404
General Contingency		460	820	80					1,360
Specific Contingency									-
Project Costs (incl contingency)	-	4,990	9,289	1,484	-	-	-	-	15,764
2007-2011 Business Plan									-
Variance to Business Plan	-	4,530	8,469	1,404	-	-	-	-	14,404
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	-	4,530	8,469	1,404	-	-	-	-	14,404
Total Release (incl contingency)	-	4,990	9,289	1,484	-	-	-	-	15,764

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	N/A		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	No
Similar Projects	Yes	Contracts in place	No	Competitive Bid	No

Variance to Business Plan

The estimated variance(s) to the 2007-2011 Business Plan will be addressed through the portfolio management process. A PCRAF is not required .

Reviewed By:

J. Xiao
Project Manager

Date: June 27, 2007

Approved By:

K. Garel
Eng & Mods Manager (Strat IV)

Date: June 27, 2007

Additional Feeder Cut and Weld Tooling 10 - 62567

Full Release Business Case Summary N-BCS-30320-00000-R000

Attachment "B"

Project Variance Analysis

	LTD N/A N/A	Choose One Last BCS N/A N/A	 This BCS N/A N/A	Variance	Comments
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material				0	
Installation – PWU, BTU				0	
Contract - Design				0	
Contract - Installation				0	
Contract - Other				0	
				0	
				0	
Interest (Capital Project Only)				0	
Project Costs (excl contingency)	0	0	0	0	
General Contingency				0	
Specific Contingency				0	
Project Costs (incl contingency)	0	0	0	0	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	0	0	0	0	
Total Release (excl contingency)	0	0	0	0	

Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
29	May	2006	Project Charter (PCH) issued for use – Complete
08	Jul	2007	Full release Business Case Summary (BCS) issued
15	Jul	2007	Tooling Purchase Contract Awarded
15	Jan	2008	D811 Priority Tooling Mock-up Testing Complete
15	Feb	2008	D811 Tools & Equipment On-site
01	Oct	2008	Main Tooling Mock-up Testing Complete
15	Dec	2008	Main Tooling Package complete
15	Jun	2009	Project Close-out complete

A Project Execution Plan (PEP) is not required

Comments:
Primary scope (development and supply of tooling) of the project will be performed by the contractors which will be retained through the contracting process. Only resources required from OPG will be project management which is well defined. A PEP is not required.

July 20, 2009

File N-CORR-08730-0296797 - T5

Nuclear Finance Directors
Site Business Support Directors
Nuclear Controllers

cc: Robin Heard
Nathan Reeve
Dwight Zerkee

Decision: Capitalization of Darlington VBO Recurring Alterations

Issue

Costs associated with the engineering, fabrication, and installation of modifications to ensure reliable air, water and electrical supplies during the Darlington Vacuum Building Outage (VBO) were initially expensed as outage incremental OM&A. Through the course of the design and installation, it was decided to make some of the work permanent modifications, and to retain some of the fabricated assemblies as reusable tools. Darlington has accordingly requested consideration for capitalization of the VBO recurring alteration costs.

Background

FIN-PROC-PA-003, Capitalization Eligibility Procedure, provides the following decision rule for capitalization:

The purchase, design, development construction or commissioning of a new asset which exceeds the materiality limit and which will provide benefits on future periods is capitalized.

The following assemblies were designed and fabricated to provide temporary services during the Darlington VBO:

- Emergency Firewater Supply from the Forebay
- Cooling Water to Irradiated Fuel Bay Heat Exchangers
- Emergency Service Water Drain
- Post-Seismic PHT Make-up for Emergency Coolant Injection Outage
- Containment Pressure Test Points and Connections
- Dousing Water Storage Drain and Fill Lines
- Vacuum Building Connections to Leak Rate Monitoring Computer
- Services for Vacuum Building Roof
- Common Pressure Relief Valve Interspace Pressure Venting Line and Pressure Equalizing Line
- Vault Cooler Alternate Drain Line
- Anchor Points, Lifting Devices, Life Lines, Engineered Scaffolds Inside the Vacuum Building
- Additional Temporary Breathing Air

During the design and fabrication of the above modifications, Darlington management realized that significant savings could be realized over the life of the station if the designs and assemblies were developed as permanent, reusable modifications. The required Engineering Change packages were developed as Recurring Temporary Alterations (RTAs), as defined in Engineering Change Control governance.

The Engineering Change Control process as defined in N-PROG-MP-0001 and N-PROC-MP-0090 allows the design and installation of RTAs that meet the following requirements:

- The RTA shall be installed and removed by an approved facility procedure that has undergone formal engineering review in accordance with N-PROC-AS-0028, Development, Review and Approval of Technical Procedures, and
- The RTA is supported by permanent design documents or Design Authority approval.

An RTA must go through the same design preparation process as a normal permanent modification to the plant. Use of the RTA process allows a modification to be designed once and then reused at a future date without going through the ECC process each time, avoiding repeated design and fabrication costs as well as overheads for the second and any subsequent application. A formal procedure is required to control the installation and application for every use to ensure it is appropriate and aligned with the designer's original intent.

A summary of the RTAs used during the Darlington VBO, together with descriptions and photographs, is attached to this memorandum.

Cost Summary

Costs associated with each of the RTAs are provided in the attached table, with a breakdown of cost type (Design, Materials, Execution, Project Support) for each individual RTA or constructed tool for 2008 and 2009. (Some design work and fabrication took place in advance of the outage in 2008.)

These costs have been examined against the criteria for capitalization in FIN-PROC-PA-003 and have found to be compliant with the following exceptions:

1. Labour costs can fall into the category of fabrication (e.g., shop assembly), field installation of permanent modifications, and field installation of fabricated assemblies. The first two cost types are incurred for the delivery of permanent assets - tools, assemblies, or permanent modifications to the plant that will remain for the life of the plant. The last cost type, field installation of fabricated assemblies, does not have a permanent nature and, in fact, will be incurred each time the RTA is used in the future. It is inappropriate to capitalize these costs, as it is also inappropriate to capitalize the de-install costs for the fabricated assemblies following the outage.

   In note 6 on the attached cost breakdown, demobilization costs (de-install) are estimated at $300k. It is therefore appropriate to estimate field installation of fabricated assemblies at a comparable cost. Accordingly, $300k is disallowed from the requested capitalization as an estimate of the costs to install the fabricated assemblies.

2. One RTA, 95817 - Connect VB Instrumentation to Containment Leak Rate Computer, has 2009 costs below the materiality threshold for capitalization as per FIN-PROC-PA-003. These costs are disallowed from the requested capitalization.

Decision

The following journal entries should be made for end of Q2 2009:

Debit Major Fixed Assets In Service for $11,354,778, with an offsetting credit to outage OM&A for Darlington ($9,870,042) and Engineering & Modifications for ($1,484,736).

Debit Minor Fixed Assets In Service for $209,244, with an offsetting credit to outage OM&A for Darlington ($176,012) and Engineering & Modifications for ($33,232).

An intermediate entry for Construction in Progress (175000000) will be made to maintain CIP continuity.

Costs will be assigned to detailed accounts in Nuclear by July month end.

Randy Leavitt
Vice President, Nuclear Finance

Nathan Reeve
Vice President, Financial Services

ONTARIO POWER GENERATION

S.A. (Stu) Seedhouse
Senior Vice President

Darlington Nuclear

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July 16, 2009

Capitalization of Darlington Recurring Alternate Configurations

Executive Summary

In support of the recently completed Darlington Vacuum Building Outage, a number of modifications were made to plant systems to accommodate system and equipment outages.

These modifications were intended to be executed as one time use. However, during detailed planning, it was realized that there would be future benefit to the plant and value for money for the corporation to modify the plant permanently at minimal incremental cost.

Of the original 30 modifications, 12 have been identified as Recurring Alternative Configurations that will utilized and provide benefits in future vacuum building, station containment and system/equipment outages. These modifications may be more appropriately classified as capital since criteria has been met based on financial materiality limit, permanent design changes, and future benefit. In addition, there were 2 constructed MFA tools.

Recommendation

It is recommended that $11.8M for 12 the modifications be capitalized as well as $0.2M for the two constructed MFA tools. Reclassification for 2008 expenditures is not recommended.

Recommended by:

FOR
Steve Woods
Director, Station Engineering
Darlington

Sabine Parks
Director, Business Support
Darlington

Stu Seedhouse
Senior Vice President
Darlington

Darlington Recurring Alternate Configurations and Constructed Minor Fixed Assets (CMFA)

Recurring Alternate Configurations - Breakdown of 2009 Year to Date Expenditures ($)

Master EC	Title	Design	Materials	Execution	Project Support	TOTAL
096402	Temp Fire Water Supply Forebay via Diesel	216,747	242,056	682,900	152,833	1,294,535
95796	EC 95796 Cooling Water to the EAST and WEST Main IFB HX's	46,188	99,998	849,725	190,168	1,186,079
098318	Drain ESW to Lower Level	91,690	218,058	955,985	213,949	1,479,682
96403	Post Seismic PHT makeup for ECI outage	394,490	139,536	693,181	155,134	1,382,341
95786	Containment Pressure Test Points & Connections	196,195	116,281	465,105	104,090	881,671
95803	DWS Drain Fill Lines	75,771	128,834	293,700	65,730	564,035
95817	Connect VB Instrmtn to Cont Leak Rate Computer	29,945	99,946	-	-	129,891
95805	Services for Vacuum Building Roof (same WO's as TMOD 9)	42,477	-	771,932	172,758	987,167
95807	Common PRV Interspace Vent Line	56,881	210,239	126,410	28,291	421,821
98379	Vault Cooler Alternate Drain	53,927	448,509	843,289	188,728	1,534,452
97494	Anchor Points, Lifting Devices, Life Lines, Eng Scaffolds	51,784	138,654	531,418	118,931	840,787
97903	Add'l Temp Breathing Air	180,516	207,445	420,578	94,125	902,664
	June Invoice Accrual	179,545				179,545
	TOTAL Recurring Alternate Configurations Requested	**1,616,156**	**2,049,556**	**6,634,222**	**1,484,736**	**11,784,669**

TOOLS - Constructed MFA - Breakdown of 2009 Expenditures ($)

95795	ECI MV122 IWST Isolation Tool	18,839	2,570	84,358	18,879	124,646
96404	Type 1 PRV Lift and Blocking tool	774	5,341	64,130	14,352	84,598
		19,613	**7,911**	**148,488**	**33,232**	**209,244**

Darlington Recurring Alternate Configurations and Constructed Minor Fixed Assets (CMFA)

Recurring Alternate Configurations - Life to Date Expenditures ($)

Master EC	Title	Expected Usage	2008	2009	TOTAL
096402	Temp Fire Water Supply Forebay via Diesel	Required for any ESW Outage. Required for planned or unexpected system unavailability. Normal planned occurrence is during system outages.	378,387	1,141,703	1,520,089
95796	EC 95796 Cooling Water to the EAST and WEST Main IFB HX's	Required for any ESW Outage. Required for planned or unexpected system unavailability. Normal planned occurrence is during system outages.	375,612	995,911	1,371,523
098318	Drain ESW to Lower Level	Required for any ESW Outage. Required for planned or unexpected system unavailability. Normal planned occurrence is during system outages.	449,485	1,265,733	1,715,218
96403	Post Seismic PHT makeup for ECI outage	Required for Containment Pressure Testing	307,572	1,227,207	1,534,779
95786	Containment Pressure Test Points & Connections	Required for Containment Pressure Testing	238,634	777,581	1,016,215
95803	DWS Drain Fill Lines	Required for Vacuum Building inspection and testing	386,034	498,305	884,339
95817	Connect VB Instrmtn to Cont Leak Rate Computer	Required for Vacuum Building inspection and testing	166,945	129,891	296,836
95805	Services for Vacuum Building Roof (same WO's as TMOD 9)	Required for Vacuum Building inspection and testing	271,996	814,409	1,086,405
95807	Common PRV Interspace Vent Line	Required for Containment Pressure Testing	287,866	393,530	681,396
98379	Vault Cooler Alternate Drain	Required for any ESW Outage. Required for planned or unexpected system unavailability. Normal planned occurrence is during system outages.	342,614	1,345,725	1,688,339
97494	Anchor Points, Lifting Devices, Life Lines, Eng Scaffolds	Required for Vacuum Building inspection and testing	227,041	721,856	948,897
97903	Add'l Temp Breathing Air	Required for planned or unexpected system unavailability. Normal planned occurrence is during system outages.	321,833	808,539	1,130,372
	Preliminary vendor engineering estimates & schedule of mods	Note 1	-	-	-
	Design Contract Accrual (June 2009 invoices)		-	179,545	179,545
	Projects & Modifications	Note 2	378,341	1,484,736	1,863,077
	Equipment Rental Costs	Note 3	-	-	-
	TOTAL Recurring Alternate Configurations Requested		**4,132,360**	**11,784,669**	**15,917,029**

Summary of Costs Above by Category ($)

DESIGN & MTL	Note 4	3,169,753	1,616,156	4,785,909
MATERIALS	Note 5	104,625	2,049,556	2,154,180
INSTALLATION/FABRICATION/COMMSSIONING	Note 6	479,641	6,634,222	7,113,863
FE and CMO	Note 2	378,341	1,484,736	1,863,077
RENTAL	Note 3	-	-	-
Summary by Category		**4,132,360**	**11,784,669**	**15,917,029**

TOOLS - Constructed MFA - Life to Date Expenditures ($)

95795	ECI MV122 IWST Isolation Tool	Maintenance Tool	122,146	124,646	246,792
96404	Type 1 PRV Lift and Blocking tool	Maintenance Tool	108,874	84,598	193,472
	TOTAL Constructed MFA Requested		**231,020**	**209,244**	**440,263**

NOTES:

1. Excludes preliminary design estimate work from Wardrop $200k
2. Estimate of CMO and Field Eng costs in support of the these modification (90% of actuals allocated to be allocated to individual modification)
3. Rental Costs $373k Excluded
4. Design & MTL costs from vendor. Excludes Station Engineering base labour and closeout activities which are normally capitalized
5. Work Order material costs from Passport
6. External execution costs (fabrication, installation, commissioning). Excludes demobilization costs (estimated at $300k)

EC 96402- Emergency Firewater Supply from the Forebay

When Emergency Service Water (ESW) is out of service for maintenance an alternate supply of firewater is required in order to provide supply for the station firewater system.

The modification is comprised of piping, headers, strainers, and valves that constitute an alternate piping system. The removable components of this permanent modification have been disassembled and stored for future use.

See attached photograph.

EC 95796 - Cooling Water to Irradiated Fuel Bay Heat Exchangers

With ESW out of service for maintenance an alternate configuration is required to supply water to the Irradiated Fuel Bay Heat Exchangers for cooling.

The modification is comprised of piping, headers, strainers, and valves that constitute an alternate piping system. Equipment associated with this modification has been uniquely identified and is stored in a shipping container for future use.

See attached photograph.

EC 98318 - Emergency Service Water Drain

This modification allows the rapid draining of a large volume of water from the ESW system to the CCW to allow for maintenance to the ESW system. During a drain, large volumes of water must be drained to the CCW system. The normal drain path was to existing sumps which were then pumped out, requiring excessive time to drain and potentially impacting critical path.

The modification is comprised of piping, headers, hoses, and valves that constitute an alternate drain system. When not in use the system is removed and stored until it required.

See attached photograph.

EC 96403 - Post Seismic PHT Makeup For ECI Outage

When the Emergency Coolant Injection (ECI) System is taken out of service for maintenance, there is a requirement to have available makeup water to the Primary Heat Transport (PHT) System of all units following a Design Basis Earthquake (DBE). This is accomplished by supplying makeup water from the Emergency Service Water (ESW) System to the PHT via the ECI system on each unit. A complete flowpath from the ESW system to the PHT system via the ECI system was established within the required credited response time after a DBE.

The modification created an alternate water supply system.

EC 95786 - Containment Pressure Test Points and Connections

There is a regulatory requirement to perform a containment pressure test every 6 years. The performance of the test requires a supply of cool dry air at a rate of 13,500 scfm to pressurize containment to 96.5 kPa.

To enable this test, an alternate system configuration consisting of 9 driers, piping, headers, supports, valves, and controls supplied by 9 rental diesel compressors. The cost of the modification excludes the rental cost.

See attached photograph.

EC 95803 – Dousing Water Storage (DWS) Drain/Fill Lines

This modification is required to refill the DWS Tank post inspection.

The modification includes a tie-in elbow connection installed on the DWS system, pump and piping system. The pump and piping are removed and stored for use.

See attached photograph.

EC 95817 - Connect VB Instrumentation to Leak Rate Monitoring Computer

As required by the Regulatory Guide R-7, the Vacuum Structure must be tested for leakage by the application of a positive pressure test once every 12 years. CNSC approval to deviate from Section 5.2.2 of Regulatory Guide R-7 is required to conduct leakage rate tests on the Darlington Vacuum Structure at negative pressures.

This modification is required to perform both positive and negative pressure tests.

This required that connection of test instrumentation be made to a monitoring computer and data logger.

Equipment is removed and stored when not in use.

EC95805 Services for Vacuum Building Roof

In order to comply with CSA Standards N285.5 and N287.7, the Vacuum Building must be opened for inspections once every 12 years.

Design of the services and facilities are required to support the planned tasks by providing lighting and power distribution, etc.

EC 95807 - Common PRV Interspace Pressure Venting Line and a Pressure Equalising Line

In previous Darlington Vacuum Building (VB) and Containment Outages, workers have experienced difficulties in maintaining the Pressure Relief Valve (PRV) J-duct water seal during the Containment Pressure Test. The J-Ducts were filled with water as a second Containment Boundary. There is a sight glass installed on each of the 18 PRV J-ducts that Operations uses to monitor the level in a J-duct. The PRV's experience varying minor leakage past the seats causing the water level to be pushed toward the Vacuum Building. The venting path used in the past was a 3/8" instrument line and OPEX has shown it is difficult to control the water within the sight glass of all 18 PRVs simultaneously. Venting into the VB basement and loss of control of the J-duct water level causes two problems:

1. The vented air contains tritium and results in a tritium release into Zone 3. This complicates ongoing maintenance in the VB basement because of the requirement for plastic suits.

2. Control of the water level in the J-duct will be part of an Approved Work Practice. If control of the level is lost, all workers in the Vacuum Building will be required to exit. This will have impact on the VB outage schedule.

Another potential impact on monitoring of the PRV J-duct water seal level exists during the VB pressure tests. During implementing test conditions for either positive or negative pressure test of the VB the water seal may move and that may vary from one J-duct to another due to some PRVs passing.

There are three test scenarios for which a solution for an unstable water seal is required. They are: 1. Containment Positive Pressure Test, 2. Vacuum Building Positive Pressure Test and 3. Vacuum Building Negative Pressure Test.

A method is required to vent leakage through the PRV seats in case of positive Containment pressure test and another method is required to provide pressure balance between the Vacuum Building Main Chamber and the Pressure Relief Valve Interspace on Containment side during the positive/negative pressure test of the Vacuum Building during a Vacuum Building Outage. Both were required to achieve stable water seal levels in the PRVs during pressure tests.

This modification provided a venting system to maintain J-duct water levels during VBO .

EC 98379 - Vault Cooler Alternate Drain

The vault coolers are supplied by Low Pressure Service Water (LPSW) and drain to the ESW return header. When ESW is out of service an alternate drain path is required on all units. This alternate configuration provides the alternate drain path when required. Some of the vault coolers are always in service.

This mod required supports for the hose routes, some of which have been left in place for future use, others are stored.

See attached photograph.

EC 97494 – Anchor Points, Lifting Devices, Life Lines, Engineered Scaffolds Inside the Vacuum Building

As required by the CNSC Regulatory Guide R-7 and CSA Standards N285.5 and N287.7, the Vacuum Building must be tested for leakage by the application of a positive pressure once every 12 years. The Vacuum Building (VB) Internal Structure and VB Upper Chamber/Dousing Tank will be inspected and tested during the 2009 VBO outage.

Service and facilities were required to support the planned tasks consisting of anchor points, life lines, lifting devices, and engineered scaffolds will be used inside the VB for facilitating the work and the transportation of personnel and equipment during future outages.

EC 97903 - Additional Temporary Breathing Air

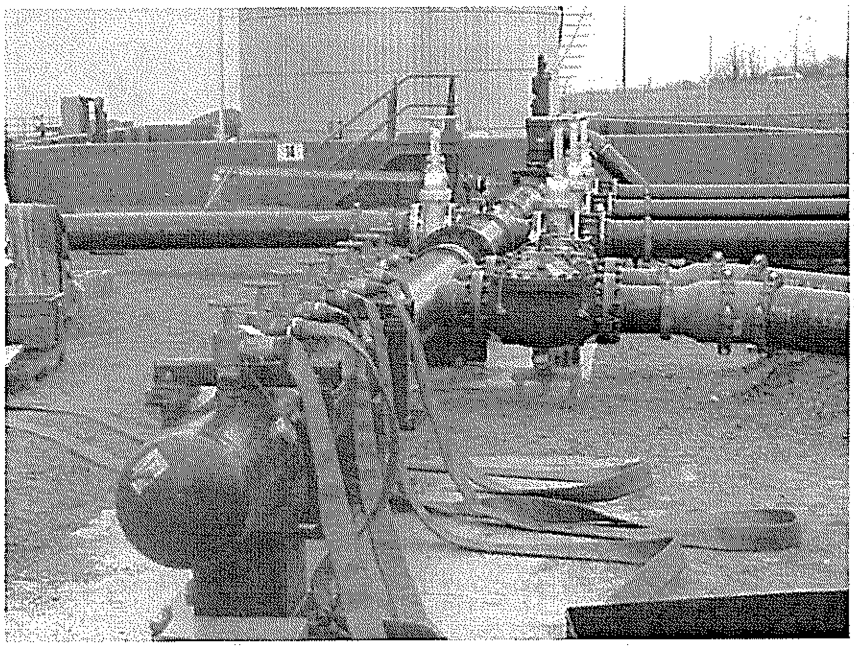
The additional breathing air modification is required for multi-unit outage or loss of existing compressors in order to provide breathing air for workers inside the vaults.

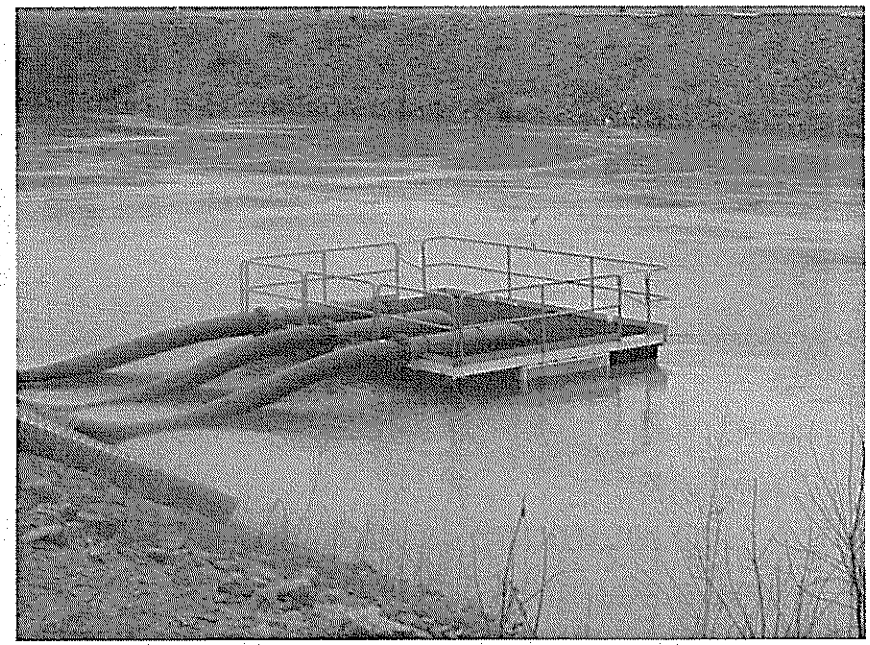
The skids were purchased as part of the modification and are stored for future use along with the piping and fittings required for the modification. The compressors are rented and are excluded from the cost breakdown.

See attached photograph.

Emergency Firewater: EC 96402

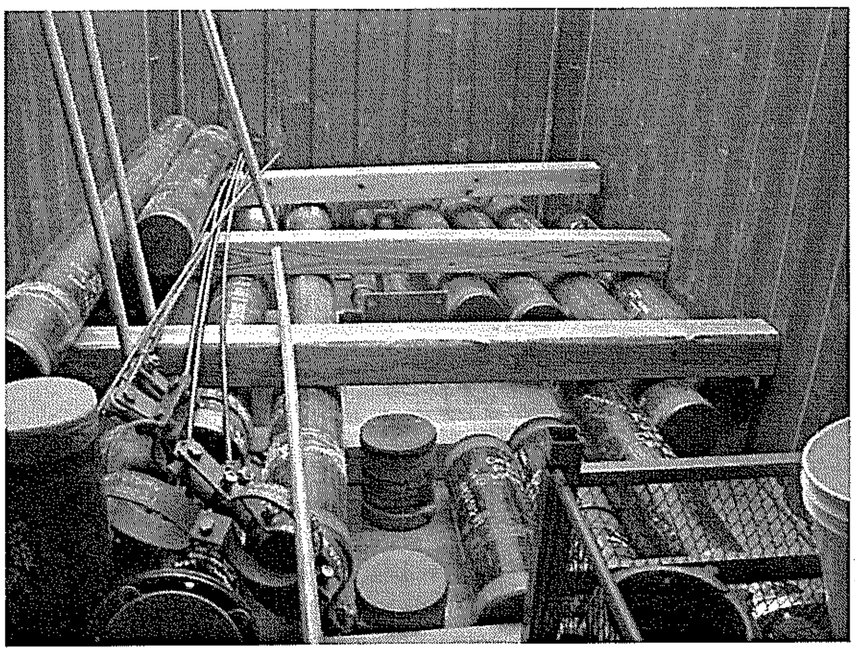
Removing ESW from service takes out the supply for the station firewater system. Therefore, when ESW is out of service for maintenance an alternative supply of firewater is required. The diesel pumps (not shown) are rentals but the piping, headers, strainers, and valves that constitute this alternate configuration have been disassembled and stored for future use.

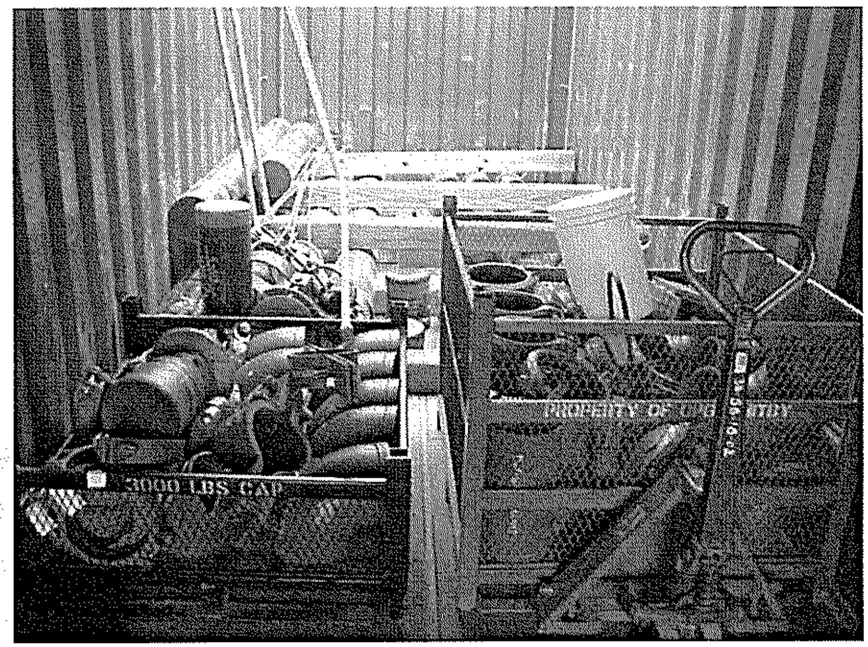




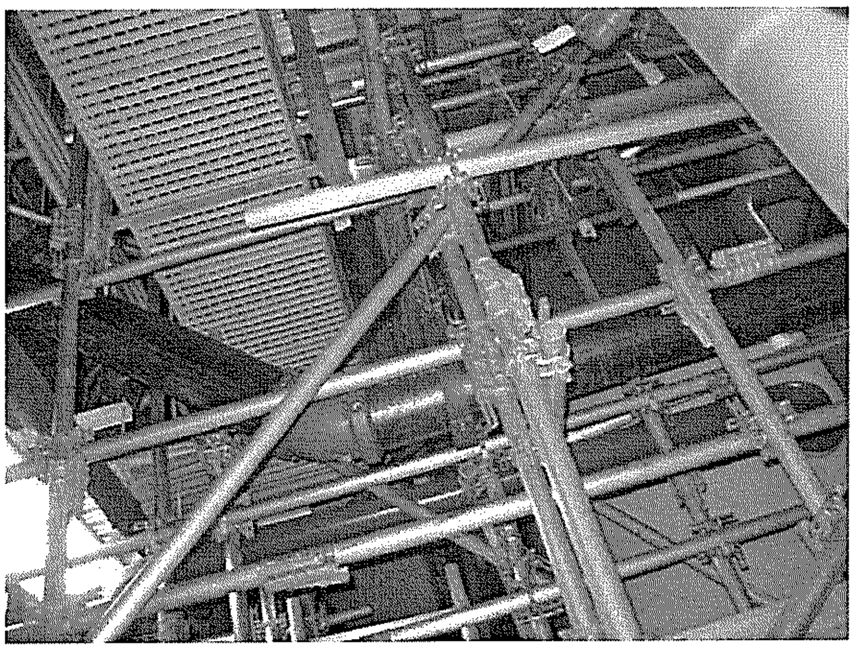
Cooling Water to IFB Heat Exchangers: EC 95796

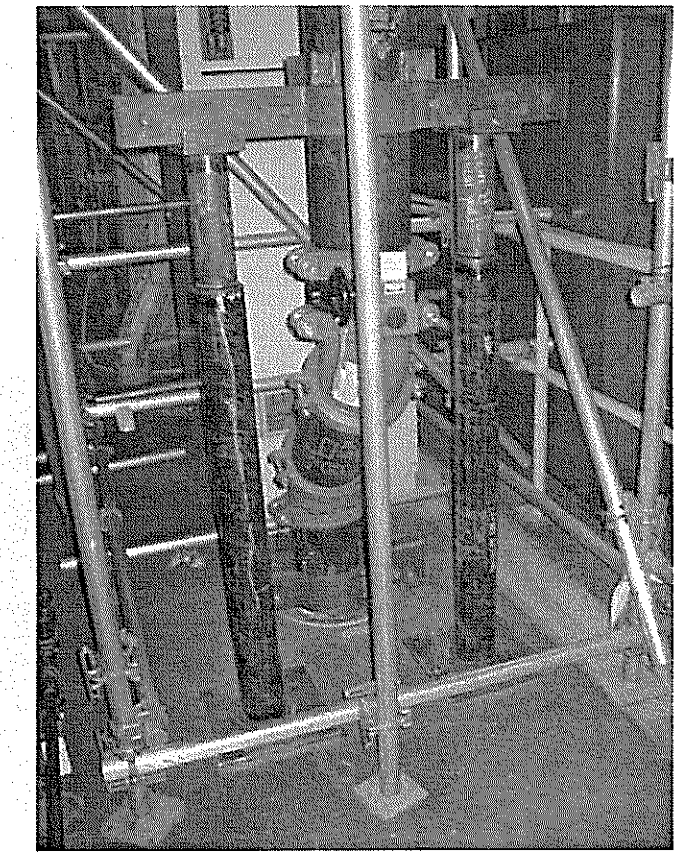
With ESW out of service for maintenance an alternate configuration is required to supply water to the IFB heat exchangers. The accompanying pictures show equipment associated with this mod being stored in a shipping container for future use.





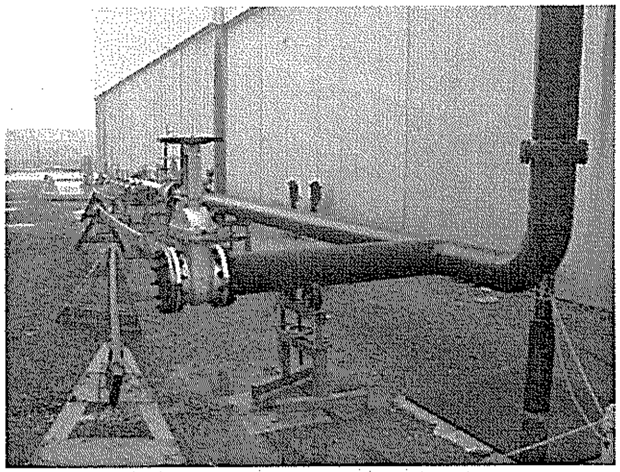
Emergency Service Water Drain: EC 98318
The modification allows the rapid draining of the ESW system to allow for maintenance.

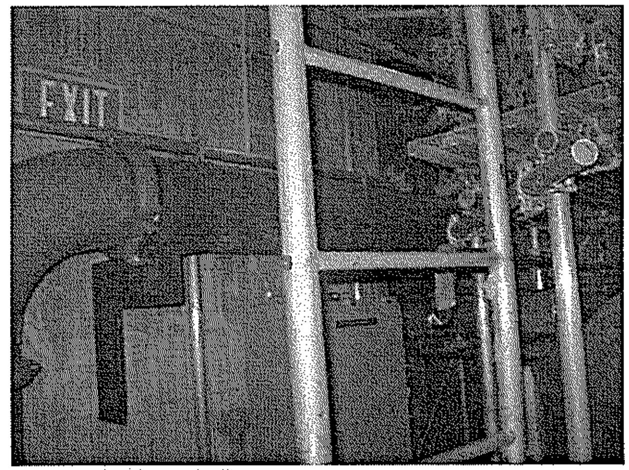


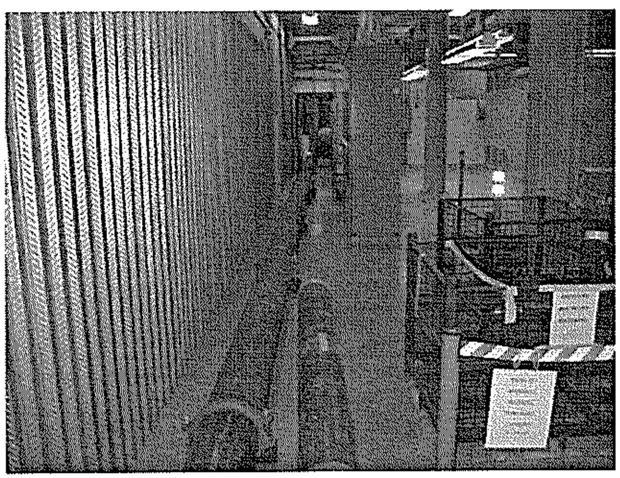


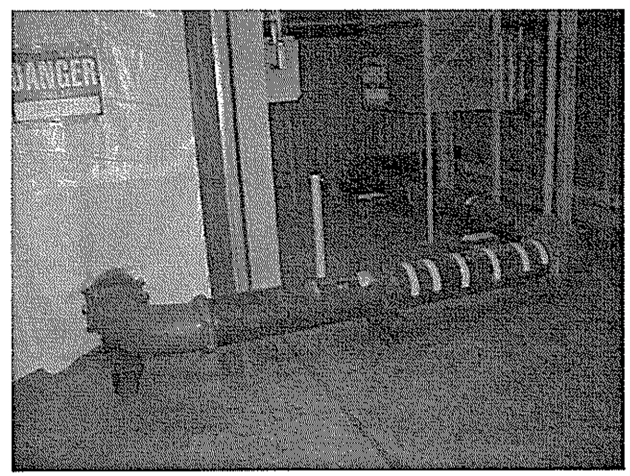
Containment Pressure Test: EC 95786:

To accomplish the VBO pressure test an alternate configuration consisting of 9 diesel compressors, 9 driers, piping, headers, supports, valves, and controls.



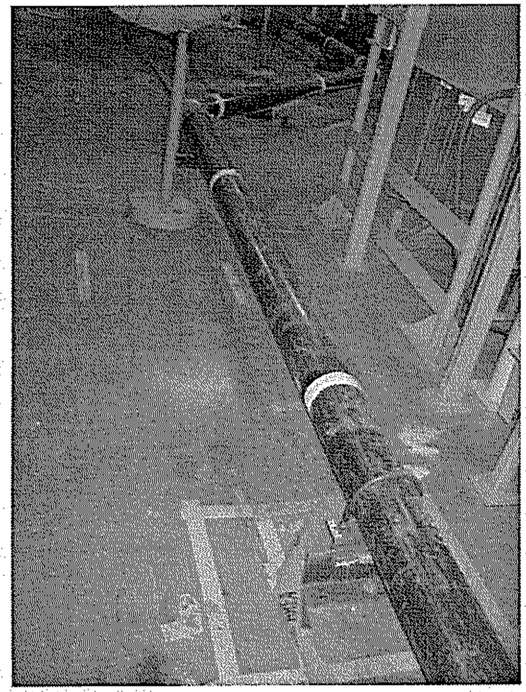


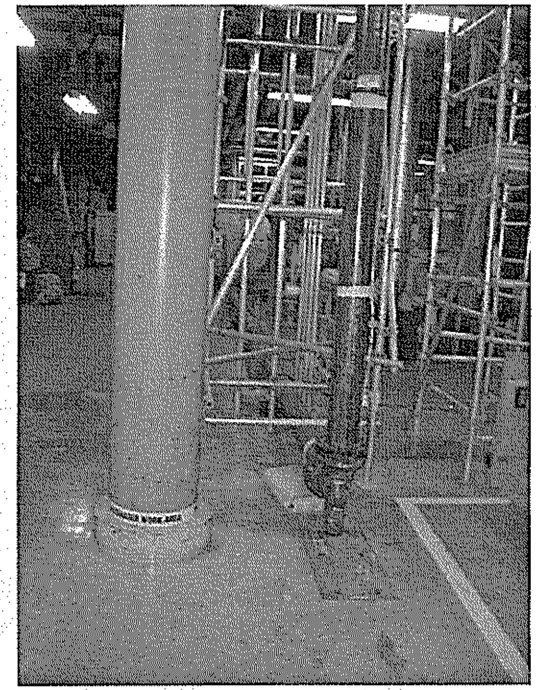


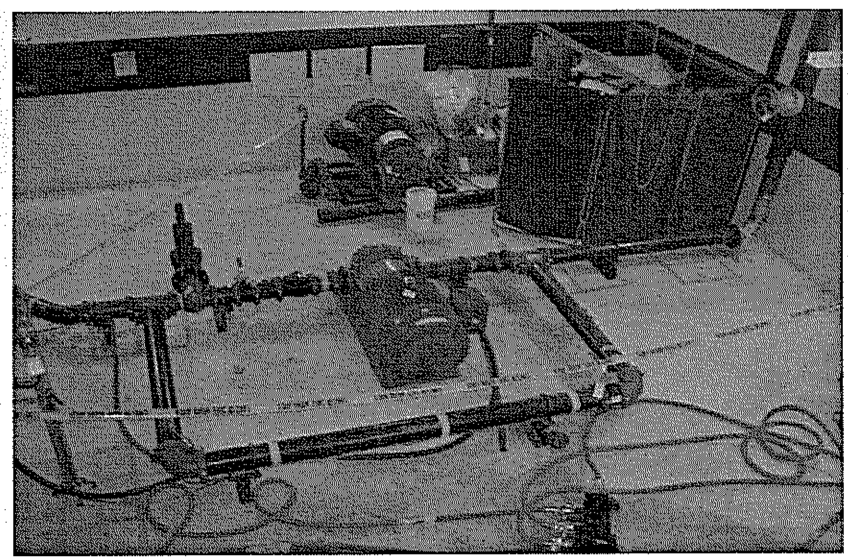


DWS Drain/Fill: EC 95803

This modification is required to refill the Dousing Water Storage Tank post inspection. Pump and piping are removed and stored for future installation with the exception of the elbow where the mod ties into the existing system. The tie in elbow remains in place for future connection.

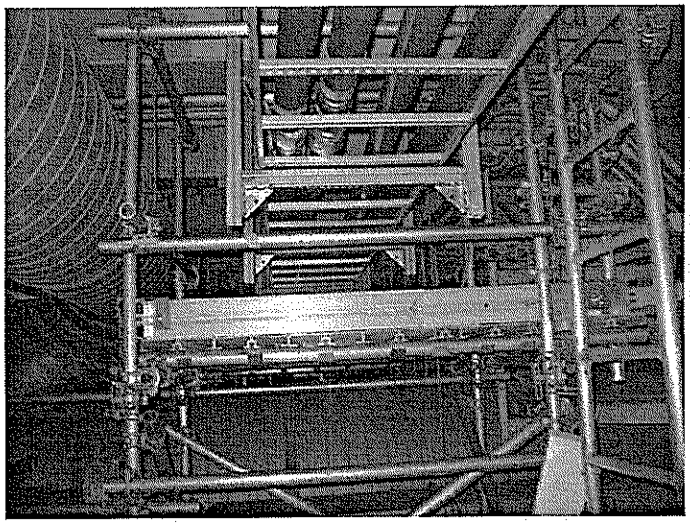


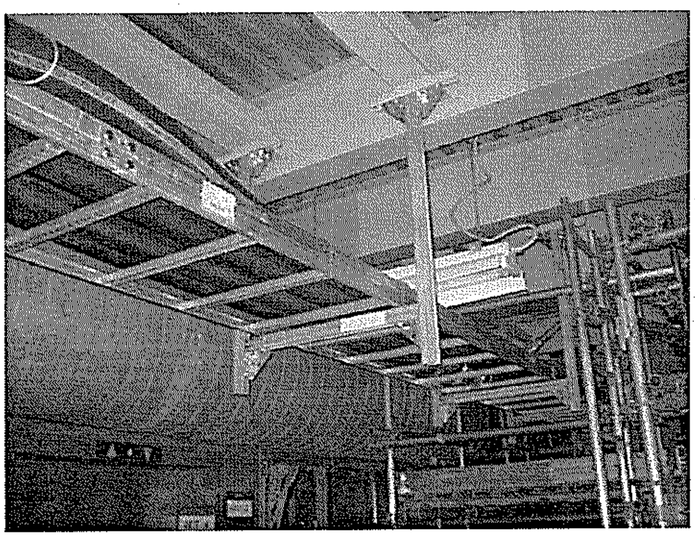


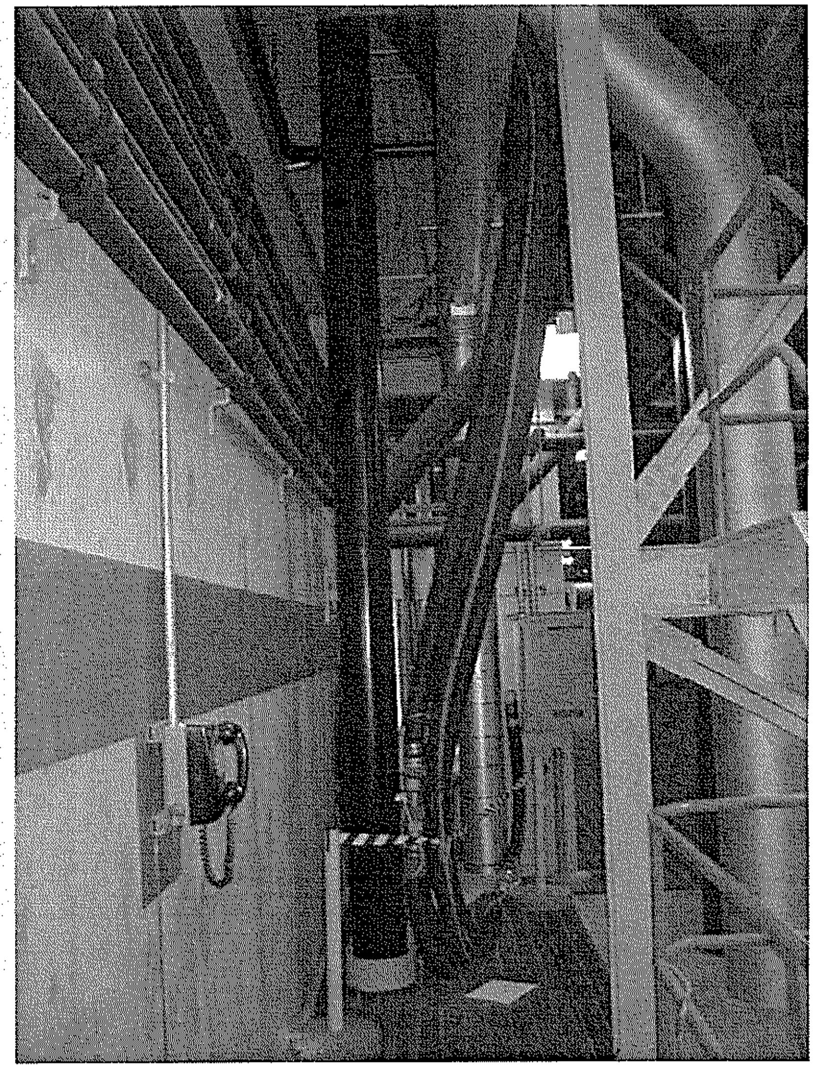


Vault Cooler Alternate Drain: EC 98379

The vault coolers are supplied by LPSW and drain to the ESW return header. When ESW is out of service an alternate drain path is required on all units. This alternate configuration provides the alternate drain path when required. Some of the vault coolers are always in service.

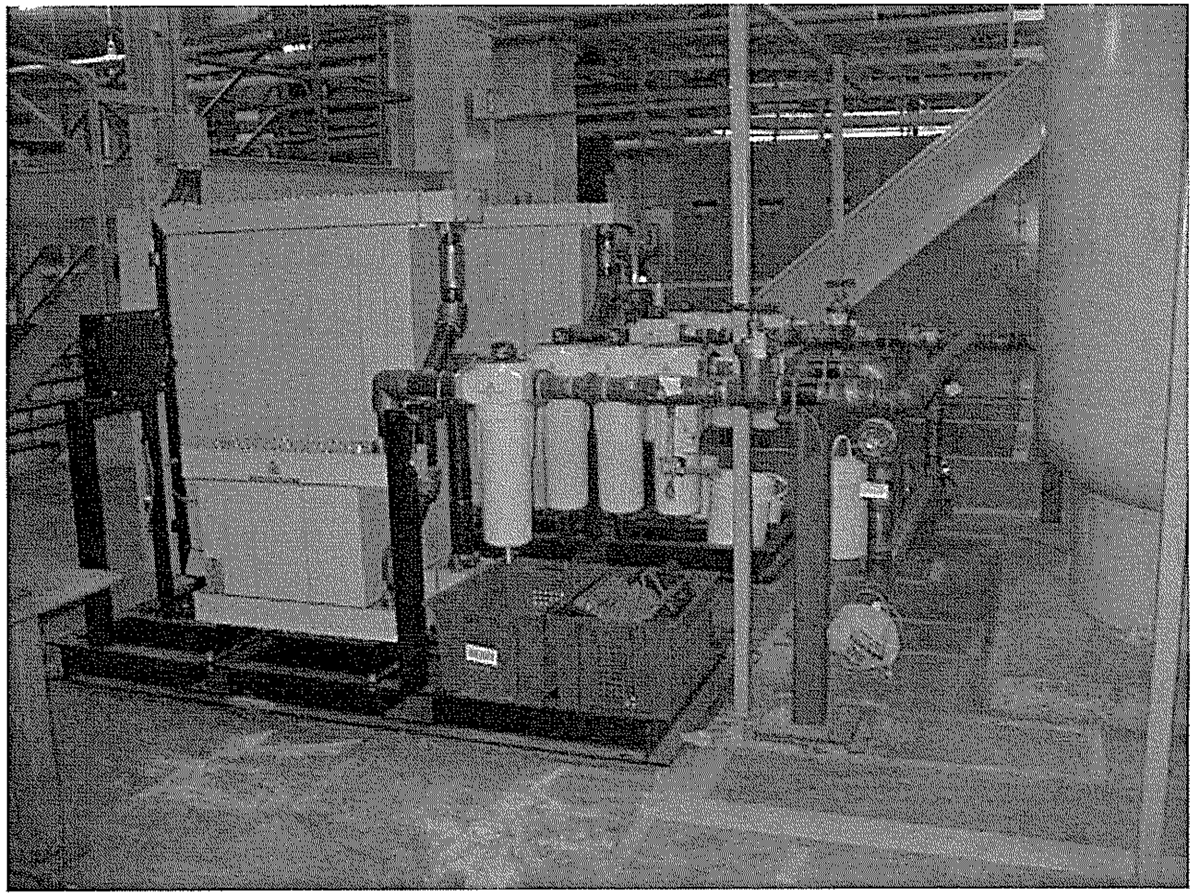






Additional Temporary Breathing Air: EC 97903

Pictured are the driers and filters for the additional breathing air modification. The skids were purchased as part of the modification and are stored for future use along with the piping and fittings required for the mods. The compressors were rented. The additional breathing air is needed whenever additional capacity is needed (multi-unit outage or loss of existing compressors).



PA Replacement of Standby Boiler 13 - 49267 Capital -

Developmental Release Business Case Summary P-BCS-73210 - 00001 - 000

1/ RECOMMENDATION:

We recommend a Developmental release of 1606 k$ (includes contingency of [redacted]$) to complete the preliminary engineering of an Auxiliary Heating System (AHS) for Pickering A & B.

The business objective of this project is to provide a reliable back-up supply of heating steam to Pickering A & B, during a six unit shutdown in winter, and thereby prevent equipment freeze damage and support the safe return to service of the shutdown units. This will be achieved by replacing the existing Standby Boiler (SB) facility with one of higher capacity and by upgrading the support infrastructure.

In order to provide freeze protection to the station, 70,000 lb/hr of steam is required on a continuous basis. The existing SB and support infrastructure cannot meet this requirement because,

- The SB is undersized and can only produce ~46,000 lb/ hr.
- The SB Steam discharge header Pressure Control Valve (PCV) can only deliver ~32,000 lb/hr.
- The Fuel Oil storage capacity is undersized and can only meet eight hours of boiler operation.

To meet the business objectives, this developmental release is required to support the preliminary engineering for the following:

- Install a new 70,000 lb/hr oil fired steam boiler with new housing.
- Upgrade the SB Steam discharge header Pressure Control Valve (PCV) to transport this steam to the station distribution header.
- Upgrade the fuel storage capacity to be capable for forty-eight hrs of uninterrupted operation of the new boiler.
- Civil, Mechanical, Electrical and Instrumentation upgrades to support the above.

There is CNSC correspondence (NK30-CORR-00531-02921) with respect to providing an adequate and reliable AHS, and REG M (AR#28079479) to track this project to completion (see background and issues – Section 2).

The total project budget estimate for the Design and Implementation is 16,956 k$ (includes contingency of [redacted]$)

$000's (incl contingency)	Class	Funding	LTD 2008	2008	2009	2010	2011	2012	Later	Total
Currently Released	Capital	N/A								-
Currently Released	OM&A									
Requested Now	Capital	Developmental		10	1,341	255				1,606
Requested Now	OM&A		-							
Future Funding Req'd	Capital	Full				1,371	12,909	1,028	42	15,350
Future Funding Req'd	OM&A		-							
Total Funding Req'd			-	10	1,341	1,626	12,909	1,028	42	16,956
Non Project Costs							450			450
Grand Total			-	10	1,341	1,626	13,359	1,028	42	17,406

Investment Type	Class	NPV	IRR	Discounted Payback
Regulatory	Capital	(932)	NA	NA

Submitted By:

for M.B. 05DEC08

Martyn Brown
Manager, Common Services

Date:

Finance Approval:

Dec 8 2008

Randy Leavitt
Director, Nuclear Investment

Date:

Line Approval (Per OAR Element 1.1 Project in Budget)

Dec 12 / 08

Martin Tulett
Director, Operations & Maintenance, Pickering A

Date:

2/ BACKGROUND & ISSUES

Building Heating System

Building heating for Pickering A & B is normally supplied by the Building Heating System (BHS), from the turbine extraction steam of any one of the operating units. It is required to provide heat and comfortable working environment for personnel and the following areas of the six operating units,

Reactor Building (RB) and Reactor Auxiliary Bay (RAB)
Turbine Hall (TH), Turbine Auxiliary Bay (TAB)
Service Wing (SW)
East and West Annex
Moderator D20 Upgrader Building
Demineralized Water Storage Tanks and connected piping

The heat supplied by BHS is subsequently distributed by the station Heating and Ventilation system (HVAC) which consists of numerous steam/ hot water heat exchangers, hot water pumps and ventilation fans. Station Class IV power is required to operate these hot water pumps and ventilation fans.

Standby Heating Systems and their condition

To address abnormal conditions (six unit shut down), there exists an oil fired steam boiler, located south of Unit 8, capable of delivering ~46,000 lb/hr of steam. It was initially designed to meet the heating requirements of Sulzer 'B', Construction Change/Shower facilities, Former Laundries, Hot Water Systems, Administration Building and Kitchen, totaling 40,100lb/hr of steam capacity. However, it is now expected to supply standby building heating steam.

The SB does not have a Deaerator, and thereby creates thermal shock to the steam drum internals, feed water piping and boiler tubes. Recent inspections (September 2008) by an external vendor confirmed the external corrosion and thinning of the boiler tubes, and has subsequently recommended installing a Deaerator, a rain cap, silencer, secondary compressor and most importantly, retube the boiler by 2010. The station continues to take all necessary effort to maintain this boiler, by conducting necessary inspection and the corrective actions required.

The PCV in the steam discharge header is capable of a through put of only ~32,000 lb/hr (confirmed by test in 2007), limiting the steam delivered to the BHS header.

The existing dedicated fuel storage tanks have a capacity of 25,000 L and limit the operation of the SB to only eight hours.

The preliminary investigation of the existing SB building confirms it is in good condition. However, a detailed investigation is required to confirm if the same building could be reused.

Regulatary Issues

SCR P-2000-03204 was initiated to review the station heating requirements to prevent D2O (Heavy Water) from freezing, and confirm that the SB meets these requirements. Following this were additional SCRs ,TOE's and CNSC correspondence relating to the performance of the Pickering Back-Up Steam Supply system ,

- **SCRs:** P-2003-04800, P-2003-01873, P-2004-10638, P-2007-02840
- **TOE:** P-TOE-73210-00001, P-TOE-71400-00003, P-TOE-67324-00001
- **REGM:** REGM-28060550, 28060551-03, 28069291-03, 28079479
- **CORR:** P-CORR-00531-00493/ 03162, NK30-CORR-00531-02921/ 03012 / 03695/ 03789 / 03871and NA44-CORR-00531-05268/ 05395

REGM 28079479 is still open, to track this project to completion.

AHS Requirements

In 2004, the CNSC requested documentation on the design basis and validation on the adequacy of the Pickering Back-Up Steam Supply system. This request and the issues identified in the previously mentioned SCRs, TOEs, CORRs and REGMs resulted in an external Design Agency completing the analysis in two phases. The first phase was completed in 2005 (NSS file P0669/RP/001, Rev 00, September 26,2005) and identified the salient functional requirements of the AHS to be,

- Heat the TH, TAB, RAB, SW, West Annexe, Moderator Upgrader building, Demineralized Water tanks and its interconnecting piping exposed to outdoor environment.
- Heating capacity sufficient to prevent freezing of light and heavy water.
- Maintain a minimum indoor temperature to ensure availability of the safety related support systems.
- Provide reasonable working environment for personnel working inside the station.

The analysis also concluded that the power requirements for the start-up and continuous operations of the AHS will be met by the Auxiliary Power System (APS).

Since the steam required to meet the above requirements is not available from the SB to the BHS header, the station has put in place compensatory measures by implementing Operating Procedure P-OP-73210-0001- Loss of Building Heating Steam. This procedure provides guidance for retaining building heat and also installing portable electric heaters in vulnerable locations.

The Conceptual Engineering Report (P-DRT-73010-00002 R0), which was based on the findings of the detailed GOTHIC modelling, completed as part of the second phase analysis of the Design Agency (P-DRT-73010-00001), has recommended the following capabilities for the AHS,

- Provide sufficient steam for freeze protecting the RB/ RAB (@ >10 °C) and the TH/ TAB (@ >4 °C), as the TH and TAB do not contain D2O systems(~70,000 lb/hr)
- Forty-eight hours capacity of dedicated fuel storage, to cater to ordering lead times for fuel oil.
- PCV in the SB discharge header to meet the SB capacity.
- Either APS or Grid to provide electrical power to meet the operating requirements of the SB and the HVAC System.

The SB 600 V loads are specifically identified in the APS load list as "Important Class IV 600 V loads", that would be re-established following a LOBES event. The hot water pumps and ventilation fans of the HVAC System are required to be a part of the discretionary loads allocated from the APS to the Unit Class IV bus, for the heat to be distributed in the station.

The AHS Design Requirements document will be updated to reflect the recommendations of the Conceptual Engineering Report.

Other Related Projects

Both Darlington and Pickering have similar requirements to provide AHS capability. Both sites will be in consultation to ensure consistency in the approach for the development of the design basis and design requirements.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2	Alt 3	Alt 4	Alt 5
Revenue	(22,401)	(7,971)	(7,971)	(12,199)	(7,971)	(7,971)	(7,971)
OM&A	(14,651)	(6,836)	(6,836)	(6,836)	(7,438)	(11,977)	(16,331)
Capital		(16,240)	(16,240)	(17,214)	(24,770)	(16,963)	(11,220)
Present Value (PV)	(19,355)	(20,287)	(20,287)	(21,745)	(26,625)	(23,256)	(20,667)
Net Present Value (NPV)	N/A	(932)	(932)	(2,390)	(7,270)	(3,901)	(1,312)
Internal Rate of Return (IRR) %	N/A						
Discounted Payback (Yrs)	N/A						

Status Quo - Not Recommended

In the absence of a project, the station as a minimum would have to to provide freeze protection the D2O systems in the RAB. To meet this objective the station would have to,

- Upgrade the PCV (to carry the full output of the SB)
- Upgrade fuel storage capacity with spill containment (to meet a minimun 48 hrs of operation).
- Re-tube the SB and complete other minor upgrades to the Standby Boiler.

This option does not meet the business objectives of providing freeze protection to all required areas of the station systems and is hence not recommended.

Alternative 1 - Purchase New Steam Boiler And Upgrade Infrastructure- No Upgrades To Existing SB - Recommended

- Install a new oil fired boiler with a capacity of 70,000 lb/hr, adjacent to the existing SB, in a new housing.
- Upgrade the fuel storage capacity from eight hours to forty-eight hours capacity, with associated spill containment.
- Upgrade the PCV in the SB discharge header to meet the SB capacity.

This alternative will maximize the use of existing infrastructure (tie-in to Steam Header, Demineralized Water Headers, Boiler Blowdown, Power Supplies, etc). A detailed investigation will be conducted to confirm if the existing SB building could be reused.

This option meets the business objectives of providing freeze protection to all required areas of the station. Since it is the most economical option to meet the station's heating requirements, it is recommended for implementation.

Alternative 2 - Delay Project By 2 Years - Not Recommended

Delaying the project only increases the risk of the station equipment and piping to freeze damage, should the AHS be required during an extended six unit shutdown. Since the EOL for Pickering is 2020, delays in implementing the recommended option would also reduce the pay back period of this investment.

Alternative 3 – Do More- Purchase New Larger Steam Boiler And Install In New Location- No Upgrades To Existing SB - Not Recommended

- Install a new oil fired boiler with a capacity of 120,000 lb/hr, in a new location between Pickering A & B, in a new housing.
- Install a new fuel storage infrastructure with capacity to operate the boiler for forty-eight hours, with the associated spill containment.

- Install necessary new infrastructure to support the operation of the boiler, such as the Steam Header, Demineralized Water Headers, Boiler Blowdown and Power Supplies.

This option exceeds the business objectives of providing freeze protection, by having the capability to maintain all required areas of the station, including TB and TAB at >10 °C. Since this not the most economical option, it is not recommended.

Alternative 4 – Do More- Puchase New Steam Boiler, Upgrade Infrastructure And Existing SB for Redundancy - Not Recommended

In addition to implementing Alternative 1, the following upgrades to the existing SB are included in this alternative,

- Install a Deaerator of required capacity.
- Upgrade the existing electrical installation such as cables and cable trays.

The re-tubing of the SB, to extend its life, would also have to be completed as part of normal station maintenance activities.

This option exceeds the business objectives of providing freeze protection, by having the capability to maintain all required areas of the station, including TB and TAB at >10 °C. With two operating boilers, equipment unavailability and the associated risks would be lower. Since this not the most economical option, it is not recommended.

Alternative 5 – Rent Oil Fired Boiler And Upgrade Infrastructure, No Upgrades to Existing SB - Not Recommended

Renting an oil fired boiler instead of purchasing a new boiler, with all other items being the same as in Alternative 1, would meet the heating requirements of the station. However, since the rental boiler is required only for the winter months, the risks/economic viability of this option is questionable for any of the following durations - on-call, six months and twelve months duration.

Transportation, regulatory approvals, installing and commissioning a rental boiler is expected to take a minimum of 2-3 weeks, the on-call rental of the boiler will not meet Pickering NGS needs for heating steam availability during emergencies. The risk to the six (6) month rental is the high probability of not receiving the same boiler, which could result in additional modifications, regulatory approvals and thereby cost to tie-in the rental boiler. Therefore, a twelve months rental contract is required to provide a reliable AHS.

This option meets the business objectives of providing freeze protection to all required areas of the station. Since it is more expensive than the purchase option, it is not recommended for implementation.

Alternative 6- Do Less- Upgrade Existing SB and Infrastructure To Improve Capacity Utilization - Not Recommended

In addition to all items in the Status-Quo option, the following additional upgrade to the existing SB is included in this alternative,

- Install a Deaerator of required capacity.

This option will not meet the business objectives of providing freeze protection to all required areas of the station systems and is hence not recommended.

4/ THE PROPOSAL

This Developmental Release BCS will be used to:

- Validate the recommended alternative with modified System Design Requirements, to be approved by the Design Authority.
- Complete the necessary documents such as SOW and DAIA to support the procurement activities to secure an external Design Agency.
- Complete Design Plan, Design Requirements, Technical Specifications and necessary drawings to support a better estimation.
- Complete all required assessments and sufficient design to support preparation of a Full Release BCS.
- Fund the use of a third party estimator.
- Complete all necessary project management documentation required for this phase, including the Project Execution Plan.
- Prepare a Full Release BCS.

5/ QUALITATIVE FACTORS

- Successful implementation of the recommended upgrade would ensure reliable supply of steam for station heating.

6/ RISKS

Risk Description	Mitigating Activities	Risk Before Mitigation										Risk After Mitigation									
See Attachment "D" For Impact Definitions	*See Attachment "D" For Probability Definitions*		Impact										Impact								
		Probability	Finance	Schedule	Quality	Corp Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety	Risk Rating	Probability	Finance	Schedule	Quality	Corp Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety	Risk Rating
Design resource availability for Design Agency is not known.	Issue contract to Design agency, who in turn will recruit necessary staff to complete the scope of work. Cost to support OPG staff included in contingency.	3	2	2	0	0	0	0	0	0	6	1	2	0	0	0	0	0	0	0	2
Equipment & Components of the modification may require custom design impacting on equipment delivery and schedule.	Review and match Specification to those commercially available.	3	3	3	0	0	0	0	0	0	9	1	3	3	0	0	0	0	0	0	3
Environment approvals may be required for the emissions from the Boiler and the containment of the Fuel Storage Tank	Review of requirements during Preliminary Engineering.	3	3	3	0	0	0	0	0	0	9	1	3	3	0	0	0	0	0	0	3
Field Location of the Boiler may change. Resulting increase cost and schedule.	Preliminary investigation has confirmed the space availability adjacent to the existing Boiler. Further investigation will be completed during Preliminary Engineering to minimize impact.	3	4	3	0	0	0	0	0	0	12	1	4	3	0	0	0	0	0	0	4
Changes to the regulations would have an impact on scope cost and schedule.	Review of requirements during Preliminary Engineering.	3	4	3	0	0	0	0	0	0	12	1	4	3	0	0	0	0	0	0	4
A change in Nuclear Safety category could increase scope. cost and schedule	The scope of this modification has been reviewed and does not impact Nuclear Safety. This will be confirmed during Preliminary Engineering	3	4	3	0	0	0	0	0	0	12	1	4	3	0	0	0	0	0	0	4
Schedule for Preliminary Design takes more than estimated.	1) OPEX from Darlington and SME's input used for estimate. 2) The SOW and DAIA expected to	3	3	3	0	0	0	0	0	0	9	1	3	3	0	0	0	0	0	0	3

	confirm schedule.																				
Design Agency skill set could impact the schedule and cost.	Will use OPG approved Design Agency. The impact is expected to be low.	2	3	3	0	0	0	0	0	0	6	1	3	3	0	0	0	0	0	0	3
Preliminary Engineering may change scope of modification	The scope of this modification is well defined. Any changes would be addressed by the scope change process.	3	3	3	0	0	0	0	0	0	9	1	3	3	0	0	0	0	0	0	3
Level of effort on Software Categorization and Human Factors may greater than estimated.	This application is non-safety related system. Preliminary Engineering will identify and address any specific issues.	3	3	3	0	0	0	0	0	0	9	1	3	3	0	0	0	0	0	0	3
Performance of selected technology	The proposed modification has similar implementations (OPEX) and is a proven design.	2	4	4	0	0	0	0	0	0	8	1	4	4	0	0	0	0	0	0	4
Next Phase																					
Detail Engineering Cost & Schedule estimate may increase.	1) Define Scope on the completion of Preliminary Engineering. 2) Issue PO for Detail Engineering.	3	3	3	0	0	0	0	0	0	9	1	3	3	0	0	0	0	0	0	3
Estimate Quality risk is minor, as Preliminary Engineering has not started and historic data not available. This could increase project cost.	Current cost estimate is based on Conceptual information. It will be reviewed and adjusted for Full Release BCS.	4	4	4	0	0	0	0	0	0	16	2	4	4	0	0	0	0	0	0	8
Execution Estimate may change based on Detail Design.	Use available historic data and budgetary estimate.	4	4	4	0	0	0	0	0	0	16	2	4	4	0	0	0	0	0	0	8
Scope of work may change.	The scope of this modification is well defined. However it would be finalized based on Preliminary Engineering.	3	4	4	0	0	0	0	0	0	12	1	4	4	0	0	0	0	0	0	4
Material Estimate may change	The material estimate is based on Budgetary Quotes. It would be adjusted for Full Release BCS.	3	2	2	0	0	0	0	0	0	6	1	2	2	0	0	0	0	0	0	2

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
TBD in Next Release			

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Later				
2.					
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

SB Standby Boiler
AHS Auxiliary Heating Steam
BHS Building Heating System
CBH Construction Boiler House
PCV Pressure Control Valve
SOW Scope Of Work
DAIA Design Agency Interface Agreement

Appendix "B" Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency)									
				Cumulative Values							
Release Type	Month	Year	2008	2009	2010	2011	2012	2013	2014	Later	Total
Developmental	Nov	2008	10	1,341	255						1,606
Full	Jul	2010	10	1,341	1,626	12,909	1,028	42			16,956
											0
											0
											0
											0
											0
											0
LTD Spent	Oct	2008									0

Comments: The Project is currently in the conceptual phase and uses seed funding money.

Appendix "C" Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	3%	R & D Tax Credit Opportunity	No
Progress Payments	N/A	Foreign Currency	Yes	Retainer Fee	No
Income Tax Rate	Corp Guidelines	PST	No	Interest Rate (Capital)	6%
Depreciation Rate (Capital)	Generating Equipment 8%	Leasing	No	Indexed Priced Contract	N/A

Comments:
See table **Impact on OM & A.** First fill of the fuel storage tanks will be an OM& A Cost (~300k$), and is not included in the project cost. Spare parts estimated at 150k$ is not included in the project cost.

Project Cost Estimate:

Design Complete	Zero to Minimal	Quality of Estimate	Conceptual + 60% to - 25%	3rd Party Estimate	No
Reviewed by Sponsor	Yes	OPEX used	Yes	Lessons Learned	N/A
Similar Projects	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Cost Sharing	No	Contracts in place	No	Competitive Bid	N/A
Fixed Price Contract	N/A	Fee for Service	No	Firm Vendor Proposal	No

Comments:
Budget quotes were received for capital equipment (Boiler, Control Valve, etc.). Cost estimate for demobilizing the existing SB is not included in the estimates. Darlington has a similar project and notes were exchanged in developing the estimate for this project.

Generation Plan Assumptions:

Station	Unit	EOL	MW	Capacity	Project Planned Outage							
Pickering A	1	N/A	N/A	N/A								
	4	N/A										
Pickering B	5	N/A	N/A	N/A								
	6	N/A										
	7	N/A										
	8	N/A										
Darlington	1	N/A	N/A	N/A								
	2	N/A										
	3	N/A										

Comments:
The recommended option and the alternatives have no impact on generation plans.

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Impact on Revenue

$000's	2009	2010	2011	2012	2013	2014	2015	2016	2016-2020	Total
Rate KWH										
Probability										
Consequence										
Risk	(1,934)	(1,973)	(2,012)	(2,052)	(2,093)	(2,135)	(2,178)	(2,221)	(5,802)	(22,401)
Other										
Base Case	(1,934)	(1,973)	(2,012)	(2,052)	(2,093)	(2,135)	(2,178)	(2,221)	(5,802)	(22,401)
Probability										
Consequence										
Risk	(1,934)	(1,973)	(2,012)	(2,052)	0	0	0	0	0	(7,971)
Other										
Recommendation	(1,934)	(1,973)	(2,012)	(2,052)	0	0	0	0	0	(7,971)
Net Impact	0	0	0	0	2,093	2,135	2,178	2,221	5,802	14,430

Comments:
Pickering LOBES OPEX suggests that up to 10 days of a six unit outage is possible. Design analysis data suggest that with the outside temperature at < -15° C the existing boiler can provide freeze protection for up to 10 days. Conceptual Design Report has data on the probability AHS triggering event as 0.061 for < -10° C and 0.007 for <-20°. Conservatively, the probability of < -10° C(0.061) is selected for calculating generation loss. Since the base case would not provide the required freeze protection, the probability of the generation loss is calculated for six units till year 2017, and three units from 2018-2020(considering EOL of Pickering A & B). For the recommended alternative the generation loss is calculated for six units from 2009-2012 (in-service date for the modification)

Impact on OM&A

$000's	Present	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019-2025	Total
Base OM&A		(2,114)	(5,324)	(1,348)	(343)	(354)	(364)	(375)	(386)	(398)	(410)	(3,235)	(14,651)
Outage OM&A													
Project OM&A													
Base Case		(2,114)	(5,324)	(1,348)	(343)	(354)	(364)	(375)	(386)	(398)	(410)	(3,235)	(14,651)
Base OM&A		(314)	(324)	(333)	(343)	(354)	(364)	(375)	(386)	(398)	(410)	(3,235)	(6,836)
Outage OM&A													
Project OM&A													
Recommendation		(314)	(324)	(333)	(343)	(354)	(364)	(375)	(386)	(398)	(410)	(3,235)	(6,836)
Net Impact		1,800	5,000	1,015	0	0	0	0	0	0	0	(0)	7,815

Comments:

Base Case OM & A includes upgrades as per Status-Quo option and to maintain the existing boiler. The recommended option costs are for maintaining the existing boiler until the new one is installed and the subsequent maintenance of new boiler.

PA Replacement of Standby Boiler 13 - 49267 Capital -

Developmental Release Business Case Summary P-BCS-73210 - 00001 – R000

Attachment "A" **Project Cost Summary**

	$000's Capital	LTD 2007	2008	2009	2010	2011	2012	2013	Later	Total
Scores Basis	Project Mgmnt & Support	-	5	222	308	670	141	19		1,365
	Engineering	-	5	827	881	238	462			2,413
	Procurement					[redacted]				
	Construction					[redacted]				
										-
										-
										-
										-
										-
	Interest (Capital Project Only)			28	90	338	244	17		717
	Project Costs	-	10	1,077	1,279	[redacted]				
	General Contingency		-	264	347	[redacted]				
	Specific Contingency									-
	Project Costs	-	10	1,341	1,626	12,909	1,028	42	-	16,956
Cash	**Adjust to Cash Basis + / -**								-	-
	Project Costs	-	10	1,341	1,626	12,909	1,028	42	-	16,956

Funding	**This Release**		10	1,341	255					1,606
	Future Release				1,371	12,909	1,028	42	-	15,350
	Project Cost	-	10	1,341	1,626	12,909	1,028	42	-	16,956

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

Budget	2008-2012 Business Plan	227	491	6,576						7,294
	Variance to Business Plan	(227)	(481)	(5,499)	1,279	10,007	847	36	-	5,962

Other	Removal Costs included above									-
	Inventory to be written off									-
	Spare Parts in Inventory					450				450

The estimated variance(s) to the 2009-2013 Business Plan will be addressed through the portfolio management process.
A PCRAF is not required

Reviewed By: [signature] NOV 26/08
Craig Verwey
Project Manager
Date:

Approved By: [signature] 26 NOV 2008
Nahil Rahman
Strat IV Manager
Date:

PA Replacement of Standby Boiler 13 - 49267 Capital -
Developmental Release Business Case Summary P-BCS-73210 - 00001 – R000

Attachment "B" **Project Variance Analysis**

	Capital	LTD	Total Project: Last BCS	Total Project: This BCS	Variance	Comments
		N/A N/A	N/A N/A	N/A N/A		
Scores Basis	Project Mgmnt & Support					
	Engineering					
	Procurement					
	Construction					
	Interest (Capital Project Only)					
	Project Costs (Scores Basis)					
	General Contingency					
	Specific Contingency					
	Project Costs (Scores Basis)					
Cash	**Adjust to Cash Basis + / -**					
	Project Costs					-
Funding	**This Release**					
	Future Release					
	Project Cost					-

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

Other	Removal Costs included above					
	Inventory to be written off					
	Spare Parts in Inventory					

Comments:

Attachment "C" Milestones and In Service Declarations

Key Milestones

Completion Date			Description
Day	Month	Yr	
02	July	2009	Design Contract Awarded (DCA)
01	Apr	2010	Preliminary Design Completed (DES)
26	Aug	2010	Full Release BCS Approved (FRF)

A Project Execution Plan (PEP) will be approved by May 2009

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%

Attachment "D"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 months)	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges **OR** Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages **OR** Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

Inter Station Transfer Bus Capacity Increase Project 13 - 49270
Full Release Business Case Summary NA44 - BCS - 54130 - 00003 – R000

1/ RECOMMENDATION:

We recommend the approval of a Full release of $19.4M (Capital including contingency) to complete the Pickering A Inter Station Transfer Bus (ISTB) Capacity Increase Project. The business objectives of this project are to:

- Design and install a permanent solution for the ISTB to meet regulatory commitments to the Canadian Nuclear Safety Commission (CNSC) under A/R 28082139
- Ensure the permanent solution for power supply to the ISTB meets design and reliability requirements
- Remove operational constraints imposed by the existing Temporary Modification (TMOD) design

During the resolution of a Technical Operability Evaluation on the Pickering A Steam Barrier, testing revealed that the ISTB did not meet Design Requirements for Voltage Drop. As a result, units 1 and 4 were out of service for approximately three months during the summer of 2007. A TMOD under Engineering Change Package EC95373 was installed in August, 2007 as an interim solution to return the Units back to service. A permanent modification is required to ensure availability of the Inter Station Transfer Bus system through the design life of the station.

An option using Class III 4KV Circuit Breakers CB8A/B (in Pickering B) through new Transfer Switches (TS) and transformers was adopted by the Pickering Joint Senior Management Board (SMB) in March 25, 2008 and a Partial Release Business Case Summary (BCS) was subsequently approved in May 2008. The objective was to comply with the September 2007 CNSC request (NA44-CORR-00531-05595) to install a permanent solution within approximately 18 months by completing the tie ins during two 10 day Pickering A (PNGSA) outages starting in April 2009.

Due to a six month delay to resolve legacy loading and equipment supplier concerns, the tie ins are now scheduled to be completed in the 2 unit PNGSA outage planned during the 2010 Vacuum Building Outage (VBO). This strategy will avoid approximately $10M of revenue losses associated with the original schedule. This benefit is partially negated by approximately $7M (without contingency) of projected additional project cost resulting from increased engineering and support effort, firmed up material and installation costs. Pickering B (PNGS-B) unit outages will not be required and commissioning is expected to be completed shortly after the VBO. As this is a large expedited project, some Integrated Operational Plan (IOP) and Outage Governance milestones will not be met. The risk associated with this strategy is outlined in detail in the proposal and Risk Section of this BCS.

As required, we have been providing the CNSC with quarterly updates on our progress. Our latest communication on Nov 15, 2008 indicates that the installation is planned to be available for service in the 2nd quarter of 2010. This schedule is based on the condition that the modification has to be commissioned with the units shutdown in order to complete all testing required to confirm that the design requirements have been met, as well as, timely procurement and delivery of materials from our suppliers.

$M (incl contingency)	Type	LTD 2008	2009	2010	2011	2012	2013	Later	Total
Currently Released	Partial	2.8	1.6						4.4
Requested Now	Full	(1.4)	11.6	4.7	0.2				15.0
Future Funding Req'd									0.0
Total Project Costs		1.4	13.2	4.7	0.2	0.0	0.0	0.0	19.4
Non Project Costs	Spare Parts			1.0					1.0
Grand Total		1.4	13.2	5.7	0.2	0.0	0.0	0.0	20.4

Investment Type	Class	NPV	IRR	Discounted Payback
Regulatory	Capital	(14.0)	N/A	N/A

Submitted By:

T. Mitchell 1 April 09
Date:
Chief Nuclear Officer

Finance Approval:

D. Hanbidge
Date:
S.V.P. & Chief Financial Officer

Line Approval (Per OAR Element 1.1 Project in Budget):

J. Hankinson May 15/09
Date:
President & Chief Executive Officer

2/ BACKGROUND & ISSUES

System Impact & Issues:

The Regulator has requested (NA44-CORR-00531-05595) that Ontario Power Generation (OPG) design, implement and install a permanent solution to the Inter Station Transfer Bus (ISTB). The schedule for completion of the installation must consider the expectation that the TMOD will be removed as soon as practical with commitments captured under NA44-CORR-00531-05718.

During resolution of a Technical Operability Evaluation (NA44-TOE-54000-00001) on the Pickering A Steam Barrier, it was discovered that actions in 2005 taken under NA44-TOE-54230-00002 were less than adequate, and that the ISTB did not meet Design Requirements for Voltage Drop. Units 1 and 4 had been out of service since June 2007. A TMOD under Engineering Change Package EC95373 was installed in August, 2007 as an interim solution to return the Units back to service. However, the TMOD has given rise to some new risks, associated with configuration, redundancy and voltage drop issues that need to be addressed by a Permanent Modification.

Under the current configuration, PB cannot complete different kinds of Class III (CLIII) and Class IV (CLIV) maintenance on Units 5 and 6 without putting PNGSA on a shutdown clock. This makes outage work more difficult to plan as alternate supplies and heat sink arrangements are required to support the work.

The 540V threshold is the minimum voltage that the Class II (CLII) battery rectifiers require to operate. In the event of insufficient voltage, ISTB will be unable to supply backup power to CLII for a Main Steam Line Break (MLSB) or provide power to critical Heating, Ventilation, and Air Conditioning (HVAC) loads used to maintain mild conditions in the Control Room and the CLIII Motor Control Centers MCC101/102 enclosures. Other equipment will be affected as well.

Current Operational Constraints:

The loss of redundancy reduces the ability of ISTB to deliver as required for a design basis MSLB event. Although a loss of redundancy still meets the minimum requirements to start the units back up, any unavailability needs to be tracked and reported to the CNSC. Moreover, there is an Operating Principles & Procedures OP&P requirement that testing and maintenance be performed without entering into a "does not meet intent" mode. In addition to loss of redundancy, the existing TMOD has placed several operational constraints on Pickering B as follows:

- Single bus operation can not be performed under the split configuration due to severe voltage drop
- Back up power supply to Motor Control Center MCC935 no longer provided by the ISTB. In order to meet Voltage Drop requirements, the TMOD removed the back up power supply (to MCC935) from the ISTB and placed it on CLIV power, therefore, it does not meet reliability requirements.
- No annunciation received on loss of back up control power to MCC935
- Extensive coordination required between Independent Electrical System Operator (IESO), PNGS-A, and PNGS-B operations when grid voltage for unit supplying Site Electrical System (SES) dips below 242 kV
- Procedures are required to ensure Make-Before-Break (MBB) transfer of CLII 600 V buses due to the fact that a Break-Before-Make (BBM) transfer will cause a transient voltage of the ISTB to dip below 480V.
- Voltage drop reduction achieved by the TMOD was marginally acceptable.

PMOD options:

A permanent solution is required that provides adequate system redundancy, ensure adequate and robust supplies are available to the ISTB loads and is relatively transparent in both mission and standby operation modes to Pickering B. To reduce the exposure of both Pickering A and B to the inherent risks of the existing TMOD, installation of the permanent modification is required to be performed on the most expedient schedule possible within reason.

The value engineering process, with third party review, was followed to select the preferred option that avoided $7M extra cost. Some of the options evaluated were:

- PNGS-B option (recommended in this report).
- PNGS-A option using Units 2/3 (U2/3) Station Service Transformers (SSTs) in conjunction with the P-A Standby Generators (SGs).
- PNGS-A option using U2/3 SSTs in conjunction with new diesel generators.

Project Expectations

The proposed installation is based on the expectations outlined in the project charter NA44-PCH-54130-00001 and initiated by ECR#11435.The primary objective is to increase the bus capacity so that ISTB can meet the design basis for current and voltage difference. Critical success factors of this project are:

- Improve voltage and current capability of the MCC incoming supply by appropriate design.
- Ease of installation and testing provision for new ISTB system.
- Remove current TMOD operational and design constraints

Current Status of Project

- SMB approved PNGS-B Option March 25, 2008
- Conceptual Design completed May 30, 2008.
- Preliminary Engineering completed January 21, 2009
- Detailed Design to be completed by August 2009
- Installation and Commissioning to be completed by June 2010

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3 PNGSA SSTs/SGs	Alt 4 PNGSA Diesel	Alt 5
Revenue					(34,271)	(22,848)	
OM&A							
Capital		(18,696)	(17,330)		(20,268)	(27,918)	
Present Value (PV)		(15,115)	(13,951)	N/A	(36,309)	(35,007)	
Net Present Value (NPV)	**N/A**	**(15,115)**	**(13,951)**	N/A	**(36,309)**	**(35,007)**	
Internal Rate of Return (IRR) %	N/A	N/A	N/A	N/A	N/A	N/A	
Discounted Payback (Yrs)	N/A	N/A	N/A	N/A	N/A	N/A	

Base Case: Not Recommended - Status Quo

The TMOD installed in August 2007 cannot be left in place indefinitely as the design was not based on a permanent platform. Operational constraints as follows:

- Challenges to maintenance planning and operational flexibility.
- Lack of redundancy in the TMOD configuration (Buss EE (BUEE) fed from unit 5 (U5) and Buss FF (BUFF) from unit 6 (U6)). Units 7 and 8 not used due to high voltage drops.
- MCC935 supply from CLIV (Not from ISTB) – Does not meet reliability requirements
- Requires extensive monitoring of grid voltage by IESO and extensive coordination between IESO and PNGS-A and PNGS-B operations if grid voltage drops below 240kV
- Split configuration of buses BUEE and BUFF challenges single bus operation, parallel operation of BUEE and BUFF required to meet system design requirements.
- Voltage drop reduction achieved by the TMOD was marginally acceptable with respect to meeting Design Requirements
- May result in forced outages
- There is a regulatory commitment to install a permanent solution

Alt. 1: Recommended - Modified Option 7a (Value Engineering Report); PNGS B Solution

This option includes installation of four 4kV/600V dedicated transformers at Pickering A to supply the ISTB. The transformers will receive power from the Pickering B 4kV Class III CB8A/B breakers through a new transfer switch, and will be situated in PNGS-A to supply the new 600V ISTB system. Tie-in of the ISTB buses will require a 2-unit PNGS-A outage (VBO). However, supply side tie-ins can be accomplished independently of Pickering B Unit conditions.

<u>This option is recommended due to the following:</u>

- Voltage profile enhanced by positioning transformers in PNGS-A
- Even and Odd supplies will provide power to the ISTB (U5/6 to BUEE & U7/8 to BUFF), therefore increasing system redundancy/reliability and remove the constraints imposed by the TMOD
- Adding Transfer Switches (remotely operated from Main Control Room (MCR) or local manual) do not require PNGS-B unit outages
- New ISTB design supports single bus operation.
- MCC935 ISTB supply restored
- Minimal impacts to existing station CL III distribution system

However, similar to the original ISTB design, the recommended Permanent Modification (PMOD) is PNGS-B dependent, and hence work coordination is required between the two stations, as well as impairments review.

Alt. 2: Not Recommended - Delay Project

This option is not recommended because it will result in leaving the TMOD installed over an extended period of time, resulting in PNGS-A forced unit outages in the event of loss of power to ISTB from units 5 and 6 (due to lack of redundancy from units 7&8). In addition, delaying the project would mean not meeting a regulatory commitment to the CNSC.

Alt. 3: Not Recommended - Option 19 (Value Engineering Report)- PNGS-A Option Using SSTs/SGs

This option includes the installation of 2 dedicated transformers at Pickering A to supply the ISTB. This option provides a PNGS-A independent solution, and hence, requires no work coordination with PNGS-B (unlike the original design). Power will be received from U2/3 SSTs in conjunction with PNGS-A SGs as follows:

- One transformer (feeds BUEE) from U2 SST secondary side and one PA SG bank
- Other transformer (feeds BUFF) from U3 SST secondary side and the other SG bank
- The transformers to be situated in PNGS-A; and step down the 4kV supply to the new 600V ISTB system.

<u>This option is NOT recommended due to the following:</u>

- Licensing issues due to the fact that the CLIII SG Switch gear and SST will not survive an MSLB event under current configuration. CLIII distribution system would require re-defining/re-classifying/& re-licensing in order for this option to be viable. There are no guarantees that the regulator would sanction such re-licensing.
- Power to the steam protected room fans will be interrupted for 3 minutes while an SG starts, which would result in CLII equipment failure. Other provisions would be required for power during these 3 minutes such as a stand alone Uninterruptible Power Supply (UPS) to supply power to fans until SGs pick up. This is a complex and expensive modification.
- Only one transformer supplying ISTB, and hence, less reliable compared to PNGS-B option.
- Requires all 3 PNGS-A SG's down in order to complete modifications (OP&P violation)
- Extensive modifications to the PNGS-A MCR

Alt 4: Not Recommended - PNGS-A Option with Diesel Generators

This option is similar to alternative 3; however, involves the addition of 2-4 Diesel Generators in place of the PNGS-A SGs in order to remove the alternative 3 technical deficiencies. As in alternative 3, this option provides a PNGS-A independent solution, and hence, requires no work coordination with PNGS-B (unlike the original design).

<u>This option is NOT recommended due to the following:</u>

- Although the use of fast start Diesels together with U2/U3 SST would be technically possible, it will be prohibitively expensive. The arrangement would require 2-4 generators, and additional breakers to protect the SST.
- Environmental Assessment would be required
- Only one transformer supplying ISTB, and hence, less reliable compared to PNGS-B option. Probability of failure of one ISTB bus is 2e-3
- Complex additions to the PNGS-A MCR would be required
- Added infrastructure, maintenance personnel and complexities

Alt. 5: Not Recommended - Other Options Listed in Value Engineering Report

Other options outlined in the Value Engineering (VE) report (NA44-REP-54130-00016) were discounted during the Engineering Decision Making (EDM) meeting held on March 19, 2008

4/ THE PROPOSAL

We recommend the approval of a Full release of $15,006K ($19,420K total project estimate) Capital funding to complete the Detailed Engineering, installation and close-out for the Pickering A Inter Station Transfer Bus (ISTB) Capacity Increase Project. The project is currently funded through a Partial Release approved May 26, 2008.

The tight project schedule allows for adherence to some on-line (IOP) and outage work management milestones; however, design issuance and assessing milestones will not follow IOP and VBO outage governance defined milestones. Given the CNSC requirement to expeditiously remove the existing TMOD supply, and the economic advantages of utilizing the planned PNGS-A outages we recommend this approach. The risks of this planned strategy will be mitigated by performing some work at risk (WARR), as per the signed modification outline package, starting in May 2009. Tie-ins will be performed during the VBO PNGS-A 2-unit outage. A PNGS-B outage will not be required to perform tie-ins to the PNGS-B supplies.

Full **Release BCS major project deliverables** are:

- Project Execution Plan
- Issue Design Packages
- Work at Risk Release (WARR) Work Plans and Field Engineering Packages
- Pre-outage (IOP) Work Plans and Field Engineering Packages for U7/8 TS tie-ins
- Outage Work Plans and Field Engineering Packages
- New and/or revised Operating and Maintenance Procedures
- Installation of new equipment and cable runs and commissioning of new ISTB system
- Post-outage Work Plans and Field Engineering Packages for U5 Transfer Switch (TS) tie-in and U8 load test
- ISTB TMOD removal and close out
- Training for Operations, Maintenance, and Performance Engineering staff
- Revised Design Packages (as required)
- Design and Project Close-out
- Post Implementation Review, Lessons Learned

This BCS assumes the abandonment in place of the majority of the TMOD and legacy installations. Only necessary removals will be performed, as part of the installation cost, to accommodate for the Permanent Modification (PMOD) installations.

Projects will identify the critical spares required for 20 years and will ensure availability prior to the final Available for Service (AFS) meeting. The cost to procure spare parts is not included in the total project capital cost as it will be funded by the inventory OM&A budget (Station OM&A budget will not be charged until parts are drawn from stores). It is estimated that the total cost to procure spare parts is approximately $1M. Cost breakdown as follows:

Item	Quantity	Cost per unit	Total Cost
Transformer (4kV/600V)	4	$100K	$400K
Disconnect Switch (4kV)	2	$35K	$70K
Transfer Switch Pair (4kV)	2 pairs	$36K per pair	$144K
Control Relays	20	$1K	$20K
Switchgear Breakers (600V)	10	$15K	$150K
Protection Relays	10	$5K	$50K
Hand-Switches (Control Room)	20	$500	$10K
Voltage Meters (Control Room)	20	$500	$10K
Indicating Lights (Control Room)	20	$500	$10K
Human Machine Interface (HMI) (Switchgear)	10	$5K	$50K
Heating units (Switchgear)	5	$5K	$25K
Ventilators (Switchgear)	5	$2K	$10K
Air Condition units (Switchgear)	5	$5K	$25K
HVAC Filters	25	$200	$5K
		Total	$979K

This project will procure nine resistive load boxes (400kVA, 600V) for commissioning purposes for a total cost of $200K. These load boxes will also be used for maintenance purposes in the future.

5/ QUALITATIVE FACTORS

- Removal of operational constraints on Pickering B as a result of the ISTB TMOD.
- Increased redundancy of the ISTB system.
- Single bus operation capability restored.
- MCC935 ISTB supply restored.
- Enhance the voltage profile:

    1. Improve the voltage drop performance against Design Requirements
    2. Provision of adequate voltage to ISTB loads

6/ RISKS (see Attachment D for details)

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
	Impact				
	1	2	3	4	5
Probability 5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Probability x Impact — Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation: Probability x Impact — Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Potential for rework due to the fact that design issuance and assessing milestones will not meet IOP and outage work management milestones in governance. **$ 103K**	-Implementing WARR strategy to ensure pre-requisites for the VBO are completed. -Working downstream deliverables in parallel. -Support groups working closely with design agency	5	12							**12**	3	9							**9**
Potential for cost increase and schedule delays due to Design packages requiring CNSC approval (VBO may not be met). Approvals need to be fast-tracked to meet IOP schedule. **$ 171K**	Regular communications maintained with the CNSC – Action Tracking AR28084390-2 & 28088132-1. Engage Senior Management and Regulatory Affairs to assist in approvals.	5	12							**12**	3	9							9
Cost/schedule impact due to Delayed Equipment Vendor documentation and less than adequate Quality causing assessing re-work. **$ 133K**	Close OPG Design & Supply Chain interface and monitoring of Vendor. Close Design, Project and Field Engineering (FE) integration with Design Agency (DA) required to limit re-work.	5	12							**12**	3	9							9
Potential for delays and increased cost to provide additional structural support to Reactor Auxiliary Bay (RAB) and Service Wing Roof caused by less than optimal civil design **$ 163K**	1. Validate structural assumptions 2. Increased oversight of civil design 3. Review existing loads on roof	5	12	15	12	9	3		4	**15**	3	8	8	3	3	1		1	**8**

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
	Impact				
Probability	1	2	3	4	5
5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Portfolio risk: Schedule delays due to changing station conditions and unforeseen issues. **$ 73K**	Projects to minimize work during VBO (or outage) by performing the following: 1. Cable trays/pulls to follow WARR or Job Jar strategy (possible, otherwise IOP) 2. Major equipment installation to follow IOP prior to outage or VBO 3. Only Tie-ins, CB8 logic work, MCR work, and testing to be performed in VBO outage 4. Equipment Removal to be performed as necessary during installation (rest of removals to be completed post outage or VBO) 5. Design reviews performed bi-weekly with the design agency to ensure schedule closely monitored and mitigating actions taken 6. Secure senior management sponsorship and commitment to obtain dedicated resources and establish aligned priorities 7. Work plans, Fabrication and Installation Package Releases (FIPRs), Inspection & Test Plans (ITPs), will be prepared in parallel with design packages, as possible.	5	15							**15**	3	6							**6**

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25		
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Potential for PNGSA forced outage (beyond VBO), schedule delays, and cost increase due to the recommended alternative not meeting business objectives (design does not meet Design intent for Voltage Drop, or other installation / commissioning issues). **$ 350K**	1. Design validated through extensive and rigorous technical reviews and Constructability, Operability, Maintenance, and Safety (COMS). 2. Factory Acceptance Test (FAT) completed for all equipment prior to shipping to ensure specs are met. 3. Comprehensive Design Requirement (DR) (Load List finalized) & Scope of Work (SOW) issued to DA. 4. P-2008-13330 findings (Unexpected low ISTB volts) incorporated in design. 5. Grid voltage requirements incorporated in design. 6. As-found Emergency Lighting loads incorporated in design; 7. Extensive analysis for transients using the Electrical Transient Analysis Program (ETAP) has shown that the recommended alternative will provide adequate power to the ISTB and meets design requirements. 8. Several load challenge reviews	10	16	15	4	6				**16**	5	**9**	3	1	2				**9**
Potential for schedule delays and cost increase due to uncertainty surrounding scope of TMOD removal. **$ 174K**	1. Projects to set up meeting with stakeholders to determine scope of TMOD removal 2. Review scope of removal with OPS during Detailed Design 3. Perform walk down to determine required scope 4. This BCS assumes substantial abandon in place of the TMOD and legacy PMOD installations	5	12							**12**	3	3							**3**

BUSINESS CASE SUMMARY

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
	Impact				
Probability	1	2	3	4	5
5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation – Probability x Impact: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation – Probability x Impact: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Potential schedule delays and cost increase due to constructability issues discovered during detailed design. **$ 158K**	1. Lessons Learned and Operational Experience (OPEX) from the ISTB TMOD incorporated. 2. Extensive involvement of Field Engineers in Design Process.	5	16							**16**	3	3							3
Potential schedule delays and cost increases due to discovery issues during installation. **$ 103K**	1. Stakeholders engaged early through COMS and walk downs. 2. Several challenge reviews were held.	5	6							**6**	3	2							3
Potential schedule delay due to unavailability of spare parts at Available for Service (AFS) meeting stemming from less than optimal spares Procurement process. **$ 50K**	1. B-2 Joint Projects and Modifications (P&M) / Supply Chain initiative underway to ensure spare parts are available at AFS for projects 2. Spare parts to be manually procured up front (along with Materials)	5	16						6	**16**	3	3						3	3
Potential schedule delay and cost increase due to internal resource unavailability (ISTB project **not** part of original VBO schedule). Some milestones not met **$ 14K**	1. Projects to coordinate and integrate with VBO team. 2. Work Orders W/Os added to VBO scope 3. Recovery plan for milestone non-compliance completed and will be closely monitored by management team	5	12							**12**	3	2							3
Potential for schedule delays due to insufficient room to lay down equipment in a common area. **$ 56K**	1. Apply early for Space Allocation Permits. 2. Coordinate with Single Point of Contact (SPOC) regarding lay down areas	5	12				6			**12**	3	1				2			3

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
	Impact				
	1	2	3	4	5
Probability 5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Probability x Impact: Before Mitigation									Probability x Impact: After Mitigation								
		Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Potential schedule delays due to permitry issues. **$ 112K**	1. Develop permitry strategy well in advance (Follow VBO integrated strategy)	5	12							**12**	3	3							**3**
Potential for schedule delays and cost increases due to conflict between Transformer T5 outage & ongoing VBO or other outage maintenance requiring T5 in service (eg. Conflicts with U7 outage and needs for T5). **$ 19K**	1. Coordinate with the System Window Coordinator (SWC) and integrate with station plans	5	12				4		6	**12**	3	3				1		3	**3**

Note: The table above shows the major risks associated with this project. See the Risk Management Plan (NA44-PLAN-54130-0260750) for a full list of the risks. The specific contingency numbers in this BCS include all risks and not just the contingencies in this table.

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Jun 2010	Dec 2010	Performance Engineering

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	CNSC requested actions under A/R 28082139 completed	Not satisfied	Satisfy CNSC commitment	Communication of results accepted by CNSC	Project Manager/ Design Projects
2.	Voltage drop and bus capability	Needs improvement to restore required design margins	Improve voltage and current capability of the bus by appropriate design	Commissioning results accepted by design and stakeholders and meet Mod Design Requirements	Design Responsible Engineer/ Plant Design
3.	Restored design margins, redundancy and reliability	Doesn't meet required design margins, redundancy and reliability	Satisfies design margins, redundancy and reliability	Commissioning results demonstrate compliance with Mod Design Requirements	Design Responsible Engineer/ Plant Design
4.	TMOD operation and design	Existing TMOD operational constraints	Remove existing constraints	Electrical Removal of TMOD	Project Manager/ Design Projects

Appendix "A" Glossary (acronyms, codes, technical terms)

- ANO – Authorized Nuclear Operator
- AR - Action Request
- AFS – Available for Service
- BUEE – Bus EE
- BUFF – Bus FF
- BTU – Building Trade Union
- BBM – Break before make
- BCS – Business Case Summary
- CLII/III/IV – Electrical Class 2/3/4
- CMO – Contract Management Office
- COMS – Constructability, Operability, Maintenance, Safety
- CB – Circuit Breaker
- CNSC – Canadian Nuclear Safety Commission
- DTL – Design Team Leader
- DR – Design Requirement
- DA – Design Agency
- ETAP – Electrical Transient Analysis Program
- EDM – Engineering Decision Making
- FIPR – Fabrication and Installation Package Release
- FAT – Factory Acceptance Test
- FEP – Front End Planning
- HVAC – Heating, Ventilation, Air Conditioning
- HFE – Human Factor Engineering
- ISTB – Inter Station Transfer Bus
- ITP – Inspection and Test Plan
- IESO – Independent Electrical System Operator
- IEV – Impact on Economic Value
- IRR – Internal Rate of Return
- IOP – Integrated Operational Plan
- IOPX – Code for work performed online
- MSLB – Main Steam Line Break
- MBB – Make before break
- MCC – Motor Control Centre
- MCR – Main control Room
- NPV – Net Present Value
- OPEX – Operational Experience
- OAR – Organizational Authority Register
- OT – Overtime
- OP&P – Operating Principles and Procedures
- PIR – Project Implementation Review
- PVBO – Code for work performed during vacuum Building Outage
- POST – Code for work performed post vacuum Building Outage
- P&M – Projects and Modifications
- PMOD – Permanent Modification
- PEP – Project Execution Plan
- RAB – Reactor Auxiliary Bay
- RC – Resource Centre
- RFP – Request for Proposal
- SMB – Site Management Board
- SOW – Scope of Work
- SSF – Secondary Side Failure
- SES – Site Electrical System

- SRE/SE – System responsible Engineer
- SG – Standby Generator
- SQA – Software Qualification Assessment
- SPOC – Single Point of Contact
- SST – Station Service Transformer
- SWC – System Window Coordinator
- SCR – Station Condition Record
- S/W – Software
- T5 – Transformer 5
- T&M – Time & Materials
- TPAR – Technical Procedure Action Request
- TS – Transfer Switch
- TMOD – Temporary Modification
- TOE – Technical Operability Evaluation
- UPS – Uninterruptible Power Supply
- VD – Voltage Drop
- VE – Value Engineering
- VBO – Vacuum Building Outage
- WBS – Work Breakdown Structure
- WARR – Work at Risk Release
- W/O – Work Order

Appendix "B" Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2007	2008	2009	2010	2011	2012	2013	Later	Total
Partial	Mar	2008	132	2,678	1,604						4,414
Full	Feb	2009	132	1,258	13,197	4,682	151				19,420
											0
											0
											0
											0
											0
											0
LTD Spent	Dec	2008	1,390								1,390

Comments:

Appendix "C" — Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	3%	SR & D Opportunity	No
Progress Payments	No	Foreign Currency	N/A	Retainer Fee	No
Income Tax Rate	Generation	PST	No	Interest Rate (Capital)	6%
Depreciation Rate (Capital)	Generating Equipment 8%	Leasing	No	Indexed Priced Contract	No

Comments:

Project Cost Estimate:

Design Complete	Up to - 40%	Quality of Estimate	Budget + 30% to - t5%	3rd Party Estimate	Yes
Reviewed by Sponsor	Yes	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	Yes	Budgetary Quote(s)	Yes	First Unit Actual Used	N/A
Cost Sharing	No	Contracts in place	Some in place	Competitive Bid	Yes
Fixed Price Contract	Yes	Fee for Service		Firm Vendor Proposal	Yes

Comments:

Contracts:

Engineering Services: Fixed price Contract in place.
SQA contract: Time & Materials (T&M).
Construction: T&M.

Budgetary Quotes:

-Construction quotes obtained from the Contract Management Office (CMO) and Field Engineering and validated by Third Party.
-Engineered Materials quotes/bids received from Vendors.

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)						
Pickering A	**1**	Mar	2020	5t3	85%	Pt09t						
	4	Mar	2020			PtOBt						
Pickering B	**5**	Mar	20t8	5t6	85%							
	6	Mar	20t8									
	7	Mar	20t8									
	8	Mar	2020									
Darlington	**1**	N/A	N/A	N/A	N/A							
	2	N/A	N/A									
	3	N/A	N/A									
	4	N/A	N/A									

Comments:

-Major equipment (No tie-ins) will be installed IOP (or Job Jar).
-PNGSA outage required for tie-ins. Tie-ins to be performed during VBO 2010.
-PNGSB outage NOT required for Transfer Switch tie-ins.

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Impact on Revenue										
$000's	**Present**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Later**	**Total**
Rate KWH										
Probability	0	0	0	0	0	0	0	0	0	**0.0%**
Consequence	0	0	0	0	0	0	0	0	0	**0**
Risk	0	0	0	0	0	0	0	0	0	**0**
Other	0	0	0	0	0	0	0	0	0	**0**
Base Case	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Probability	0	0	0	0	0	0	0	0	0	**0.0%**
Consequence	0	0	0	0	0	0	0	0	0	**0**
Risk	0	0	0	**0**	0	0	0	0	0	**0**
Other	0	0	0	0	0	0	0	0	0	**0**
Recommendation	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Impact	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Comments:

This is a Regulatory Project. The Base Case is assumed to be Zero. There will be no impact on Revenue as the tie ins are not critical path work for the 2 unit PNGSA outage planned during the 2010 VBO.

Impact on OM&A										
$000's	**Present**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Later**	**Total**
Base OM&A	0	0	0	0	0	0	0	0	0	**0**
Outage OM&A	0	0	0	0	0	0	0	0	0	**0**
Project OM&A	0	0	0	0	0	0	0	0	0	**0**
Base Case	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Base OM&A	0	0	0	0	0	0	0	0	0	**0**
Outage OM&A	0	0	0	0	0	0	0	0	0	**0**
Project OM&A	0	0	0	0	0	0	0	0	0	**0**
Recommendation	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Impact	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Comments:

This is a Capital Project. No incremental impact on OM&A due to routine testing post installation.

Notes for Attachment A (Next Page):

-Spare Parts not included in total project cost.
-Removal cost included in installation.

Inter Station Transfer Bus Capacity Increase Project 13 - 49270
Full Release Business Case Summary NA44 - BCS - 54130 - 00003 – R000

Attachment "A" **Project Cost Summary**

	$000's Capital	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnt & Support	199	1,452	643	78					2,373
	Engineering	1,039	1,931	468	51					3,489
	Procurement	47	3,989	4	-					4,040
	Construction	80	3,634	1,524	21					5,259
	Other									-
										-
										-
										-
										-
	Interest (Capital Project Only)	24	313	387	-					724
	Project Costs	**1,390**	**11,319**	**3,025**	**151**	**-**	**-**	**-**	**-**	**15,885**
	General Contingency		882	795						1,677
	Specific Contingency		996	862						1,858
	Project Costs	**1,390**	**13,197**	**4,682**	**151**	**-**	**-**	**-**	**-**	**19,420**
Cash	**Adjust to Cash Basis + / -**								-	-
	Project Costs	**1,390**	**13,197**	**4,682**	**151**	**-**	**-**	**-**	**-**	**19,420**
Funding	**Current Release**	2,810	1,604							4,414
	This Release	(1,420)	11,593	4,682	151					15,006
	Future Release								0	0
	Project Cost	**1,390**	**13,197**	**4,682**	**151**	**-**	**-**	**-**	**0**	**19,420**

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

		LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Budget	**2009-2013 Business Plan**	1,964	7,651	406	-					10,021
	Variance to Business Plan	**(574)**	**3,668**	**2,619**	**151**	**-**	**-**	**-**	**-**	**5,864**

		LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Other	**Removal Costs included above**									-
	Inventory to be written off									-
	Spare Parts in Inventory			1,000						1,000

The estimated variance(s) to the **2009-2013 Business Plan** will be addressed through the portfolio management process.
A PCRAF **is not required** .

Reviewed By: [illegible], Mar 13, 2009 (for JANE CLEMO)

Jane Clemo
Project Manager (acting) Date:

Approved By: 13 Mar 09

George Makdessi
Strat IV Manager (acting) Date:

Inter Station Transfer Bus Capacity Increase Project 13 - 49270
Full Release Business Case Summary NA44 - BCS - 54130 - 00003 – R000

Attachment "B" **Project Variance Analysis**

	Capital	LTD Dec 2008	Total Project Last BCS Mar 2008	Total Project This BCS Feb 2009	Variance	Comments
Scores Basis	Project Mgmnt & Support	199	638	2,373	1,735	Project duration streched by one year due to changed strategy to use VBO outage for installation tie-in's. Front End Planning (FEP) Work Breakdown Structure (WBS) for Project Mgmnt includes all field preparation efforts by FE and CMO as well (unlike original estimate).
	Engineering	1,039	2,386	3,489	1,103	Finalized design requirements available for this release, detailed project scope is developed and as a result, design agency original estimate increased.
	Procurement	47	1,852	4,040	2,188	Finalized design requirements led to material quantity and cost changes. Original estimate included budjet quotes from a supplier no longer on Approved Supplier List (ASL)
	Construction	80	3,861	5,259	1,398	Scope and strategy of installation was not finalized in original Partial Release estimate
	Other				-	
					-	
					-	
					-	
					-	
	Interest (Capital Project Only)	24	337	724	387	Project duration streched by one year due to the changed strategy of utilizing VBO outage installation.
	Project Costs (Scores Basis)	**1,390**	**9,074**	**15,885**	**6,811**	
	General Contingency		1,553	1,677	124	
	Specific Contingency		1,130	1,858	728	
	Project Costs (Scores Basis)	**1,390**	**11,757**	**19,420**	**7,663**	
Cash	Adjust to Cash Basis + / -	N/A			-	
	Project Costs	**N/A**	**11,757**	**19,420**	**7,663**	
Funding	Current Release	N/A		4,414	4,414	
	This Release	N/A	4,414	15,006	10,592	
	Future Release	N/A	7,343		(7,343)	
	Project Cost	**N/A**	**11,757**	**19,420**	**7,663**	

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

Other	Removal Costs included above				0	
	Inventory to be written off				0	
	Spare Parts in Inventory				0	

Comments:

Attachment "C" **Milestones and In Service Declarations**

Key Milestones

Completion Date			Description
Day	Mth	Yr	
18	Feb	09	AISC Disposition Full Release Business Case Summary
26	Feb	09	Long Lead Time Material Contracts Awarded
15	Apr	09	Project Execution Plan Approved
17	Apr	09	Full Funding Release Approved
30	Apr	09	Installation Labour Contracts Awarded
31	Aug	09	Design Documents Approved and Issued -EC Approval
29	Oct	09	IOPX Remaining Equipment or Material Staged
15	Jan	10	PVBO Work Plans Issued
29	Jan	10	PVBO and POST Work Package Assessment Completed
3	May	10	Start of Installation VBO
20	May	10	Partial AFS U7 BUFF
25	May	10	Partial AFS U6 BUEE
25	Jun	10	Available for Service Final for U5 and U8
30	Aug	11	Project Complete Milestone

A Project Execution Plan (PEP) **will be approved by Feb 2009**

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%
Jun	2010	Available for Service Final for U5 and U8	15,220	100%
Aug	2011	Project Closure	665	

Attachment "D"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 months)	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges **OR** Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages **OR** Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

Weld Overlay Project 10 - 62568 Capital 10 - 62435 OM&A
Full Release Business Case Summary N - BCS - 30751 - 10002 – R000

1/ RECOMMENDATION:

Approval is requested for the Full Release of $53.2M Capital (including contingency) and $[redacted] OM&A (specific contingency) to proceed with the next stage of the Weld Overlay Project which will design and manufacture weld overlay tooling for those Darlington outlet feeders that are life-limited by pipe wall thinning caused by Flow Accelerated Corrosion (FAC). This brings the total costs to $71M.

The business objective of this project is to reduce the cost of managing life-limiting feeder thinning by developing a repair alternative to the current exclusive use of Cut and Weld tooling for replacing thinned feeders. It is estimated that using weld overlay repair technology in conjunction with Cut & Weld tooling (as necessary), will provide a financial benefit in the range of approximately $38M - $143M (NPV) with a 19% – 45% IRR. (See Alternative Section for details). This estimate is based primarily on the assumptions:

- Less overall time required to repair a feeder during a Darlington outage
- Lower execution costs per feeder repair

To date, there has been four partial releases for Weld Overlay under project # 62435 (OM&A): $1.5M in 2005-2006 for the Definition stage (Proof-of-Concept); $700K in 2006-2007 for the Pre-Tool Development phase, $3.7M in 2007 for Stage I (Preliminary Design of Tool and process) and; $10.6M in 2008 to complete Stage I which is in progress. The project is currently managing Stage I Preliminary Design contracts with two separate vendors in an effort to maximize the probability of project success.

A 2011 Darlington Spring Outage In-service date for this process and tool significantly increases its economic benefits, which necessitates seamless transition into Stage II of the Weld Overlay Project. For this reason, this request for Capital funding approval is being made prior to the completion of Stage I, and prior to estimates being provided by the vendors. The budgetary estimates included in this request are based on costing experience with the similar Cut and Weld tooling, and are considered conservative. Also, a large amount of contingency has been assigned in this BCS to account for the uncertainty.

At the end of Stage I, a revised BCS will be prepared with updated project costs within the value of this release request, and updated risks to reflect the work completed in Stage I. The project team will present the technical and business case as a formal recommendation in a decision meeting, chaired by the CNE (see Attachment D). This revised BCS will be presented for signature during this decision meeting with the CNE, and follow up meetings with the CNO, COO, and CEO. If approved, only the value in the revised BCS will be released. At this time, outage savings will be quantified for 2010 - 2014 business planning - P.Haavik.

1000's (incl contingency)	Funding	Type	LTD 2008	2009	2010	2011	2012	Later	Total
Currently Released	Partial	OM&A	3,647	12,887					16,534
		Capital							-
Requested Now	Full	OM&A			1,000				1,000
		Capital		5,050	45,060	3,084			53,194
Future Funding Req'd	N/A	OM&A							-
		Capital							-
Total Project Costs			3,647	17,937	46,060	3,084	-	-	70,728
Other Costs									-
Ongoing Costs									-
Grand Total			3,647	17,937	46,060	3,084	-	-	70,728

Investment Type	Class	NPV	IRR	Discounted Payback
Value Enhancing	Capital & OM&A	38M - 143.4M	19% - 45.5%	5 - 3 Years

Submitted By:

T. Mitchell
Chief Nuclear Officer
Date:

Finance Approval:

For [signature]
D. Hanbidge
S.V.P. & Chief Financial Officer
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

[signature]
J. Hankinson
President & Chief Executive Officer
Date: May 15/09

2/ BACKGROUND & ISSUES

Degradation of primary heat transport system feeders by flow-accelerated corrosion (FAC) is a significant life-limiting threat to OPG Nuclear plants. Cut and weld methods currently used for replacement of thinned feeder sections requires a number of preparatory activities (including channel defuelling, isolation and draining) that cannot be completed in parallel. As the number of feeders to be replaced increases, the time required to complete the repairs has a more significant impact on the duration of planned outages.

Another approach to feeder repair is to build up the feeder wall thickness by weld overlay, which deposits a layer of weld metal on the exterior of the pipe work. Advantages of this method include elimination of the need to defuel and drain the channel, a potential reduction in the time required for repairing each feeder, as well as an anticipated reduction in worker radiation dose and the amount of loose contamination and radioactive waste produced.

Weld overlay is a demonstrated technology that has been used successfully in both nuclear and non-nuclear repair applications. This current proposed application of the technology is considered a first of a kind due to the specific conditions of the repair. These include, that it is to be performed on thin wall, carbon-steel nuclear class 1 piping with specific material property requirements; it is to be applied with very tight clearances making tooling design difficult, and the pipe will be full of water during the application. In the original proof of concept study, weld overlay was demonstrated as being feasible for these specific conditions, however residual technical risks were identified. These risks include material properties (hydrogen, hardness, and residual stress), and miniaturization of the tooling.

During Stage I Preliminary Engineering (currently in-progress), the residual risks identified during the proof of concept work are being addressed. Weld processes are being developed to enhance favourable material properties, inspection techniques are being developed for pre and post overlay requirements, and a conceptual tool design will be provided based on tooling requirements and available clearances at the feeder hub to pipe weld area. Two vendors are currently contracted in competitive, parallel efforts to successfully complete Stage I in order to maximize the probability of project success.

A 2011 Darlington Spring Outage in-service date for this process and tool significantly increases its economic benefits, which necessitates a seamless transition into Stage II of the Weld Overlay Project. For this reason, this request for Capital funding approval is being made prior to the completion of Stage I, and prior to estimates being provided by the vendors. The budgetary estimates provided in this request are based on costing experience with the similar Cut and Weld tooling, and are considered conservative. Also, a [redacted]% contingency has been assigned in this BCS to account for the uncertainty.

At the conclusion of Stage I, an updated economic analysis and revised BCS will be prepared using vendor provided budgetary estimates for Stage II, and a formal decision meeting will be held to determine whether to recommend proceeding with weld overlay tool detailed design and manufacture. The basis for the decision meeting may be found in Attachment D. If a recommendation to proceed is decided, a second decision meeting will be held with the CNO to present the case and obtain his acceptance. The CNO will then take the recommendation to the COO and then to the President for approval and final release.

The Weld Overlay Project is being executed in two stages as detailed in the table below. This staged funding release and execution is being used to minimize the financial risk, and provide adequate assurance that the repair technique and tooling is technically acceptable.

Stage 1 (OM&A) consists of: Proof of Concept (complete); Pre-Tool Development (complete); and Preliminary Engineering (in progress). To date, the concept of weld overlay has been demonstrated as a feasible repair technology and residual technical risks have been identified. The Preliminary Engineering phase will resolve the technical risks which involve primarily material property issues, and will provide a conceptual tool design.

Stage 2 (Capital) consists of three distinct phases: Detailed Design & Prototype Fabrication; Fabrication & Mock Up Testing; and Commissioning. At the end of this stage of the project, the tool sets will be declared as Available For Service, Regulatory approval will have been granted, and multiple tool sets ([redacted] currently projected) will be available for use at Darlington.

Stage / Cost Type	Phase	Cost Area	Cost Item	Estimated Cost (K$ CND) Includes Contingency							
				2005	2006	2007	2008	2009	2010	2011	Total
1 OM&A	1	Proof-Of-Concept	Develop Concept and identify major risks	1,275	145						1,420
		Pre-Tool Development	Development of tool requirements		260	370					630
		Preliminary Engineering (Currently in Progress)	Material Property Issue Resolution, Preliminary Design - Tool / Process			127	1,470	12,887		-	14,484
2 Capital	2	Detailed Design & Prototype Fabrication	Tool Development & Commissioning					5,050	45,060	3,084	53,194
	3	Fabrication & Mock Up Testing									
	4	Commissioning									
2 OM&A	(OM&A Specific Contingency)								1,000		1,000
				1,275	405	497	1,470	17,937	46,060	3,084	70,728

A total of $53.2M Capital (including contingency) and $1M OM&A (specific contingency) is requested to perform Stage II of the Weld Overlay project. This release request Includes a $[redacted]M specific contingency to cover uncertainties regarding applicability of PST which is dependent on Tool ownership (title) by OPG or entry of a non-OPG owned tool into Ontario which may be built in the USA. Applicability of PST will not be known until the successful completion of Stage I; therefore, [redacted]% of tool development costs have been reserved in a specific contingency. This funding will only be released if PST is required.

This release request also includes a specific contingency of $[redacted]M OM&A to deal with uncertainties regarding on-reactor commissioning in 2010. If the feeder is repaired and left in-service, it is Project OM&A; if it is repaired and cut out it is Project Capital. At this point in the project, it has not been decided whether the feeder will be left in service or cut out.

This full release business case summary and the associated economic analysis ("Economic Analysis to Support Weld Overlay BCS N-BCS-30751-10002", N-REP-30751-10007) considers only the weld overlay candidates at Darlington based on the latest feeder replacement schedule. The analysis assumes that weld overlay repair will be performed on the feeder repair candidates from 2011 onward.

Since the original Economic Analysis assessment in 2007, the 6 probe inspection results at Darlington have shown an increased number of feeders that have life limiting thinning in the Grayloc area (as projected in N-BCS-30751-100000-R000) which considerably strengthens the economic viability of this project with the additional funding requested. As well, 6 probe inspections for all Darlington units are not yet complete and may reveal additional life limited thinned feeders.

This project includes only the costs associated with developing, delivering and commissioning the Weld Overlay tooling. Weld Overlay field application costs will be addressed outside this project; however, these projected (listing estimates) costs have been included in the NPV calculations.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

The economic benefit of introducing weld overlay tooling is presented in this BCS as a potential NPV range. This approach was taken for the following reason:

The actual number of feeders scheduled for repair in any given outage (until Unit end-of-life) can vary because of new inspection results and emergent repair requirements. There are currently two methods used for determining feeder repair candidates (Reference NK38-CALC-33160-10044):

1. **Current Assessment:** The current case provides the remaining life of feeders with the current assessed wall thinning rates as determined by the *rate from initial* methodology for feeders limited adjacent to the Grayloc weld. It is commonly assumed that the feeder pipe adjacent to the Grayloc weld began life at a wall thickness lower than that of nominal pipe thickness. Thus, the methodology is assumed to provide conservative estimates of the wall thinning rate.
2. **Risk Informed:** The risk informed method incorporates all the information that is available for each feeder. As described, the formal feeder thinning assessment utilizes a single thinning rate to ensure conservatism in estimating remaining life. However, for replacement planning purposes it is recognized that over conservatism puts a strain on long term planning practices.

The Risk Informed method allows for a more realistic approach to determining which feeders require replacement, however, by reducing some of the conservatism, there is an inherent risk of under estimating thinning rates, which could result in emergent replacements. Because of this risk, and the risk of emergent replacement requirements coming from future inspections, two (2) separate economic analyses were conducted, using a set of feeder repair candidates derived from each estimating method. The result of each analysis (NPVs) represents the potential range of economic benefits/losses of introducing weld overlay tooling.

Risk Informed Scenario

$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay Project (1 Year)	Alt 3	Alt 4	Alt 5
Revenue	(265,956)	(145,853)	(145,853)	(157,929)			
OM&A	(170,802)	(125,618)	(121,971)	(126,299)			
Capital	0	(51,205)	(51,205)	(51,205)			
Present Value (PV)	(201,308)	(165,731)	(163,233)	(170,893)			
Net Present Value (NPV)	**N/A**	**35,576**	**38,074**	**30,414**			
Internal Rate of Return (IRR) %	N/A	17.7%	19.1%	17.7%			
Discounted Payback (Yrs)	N/A	8.2	8.1	8.3			

Current Assessment Scenario

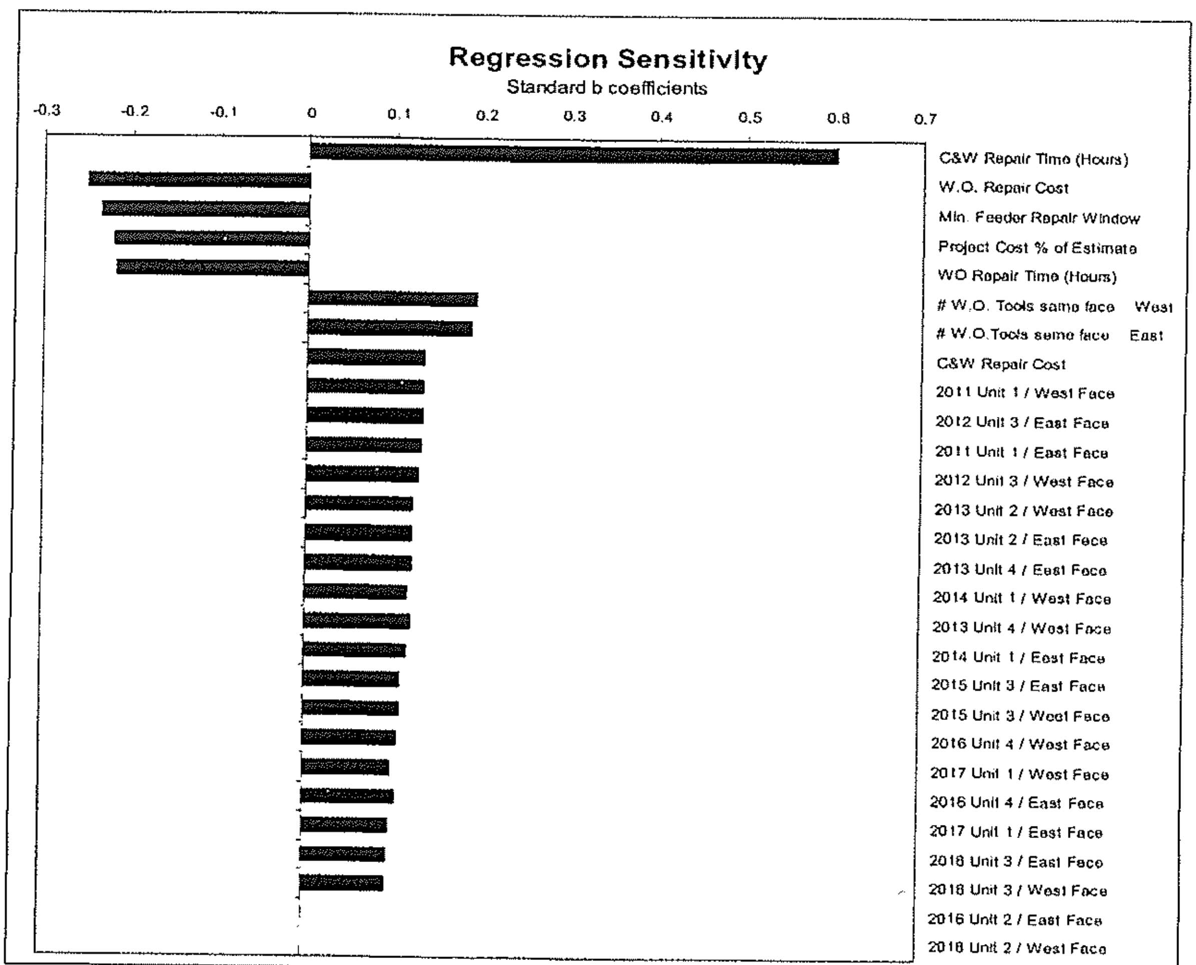
$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay Project (1 Year)	Alt 3	Alt 4	Alt 5
Revenue	(573,891)	(311,812)	(311,812)	(335,964)			
OM&A	(370,833)	(252,997)	(249,350)	(258,266)			
Capital	0	(51,205)	(51,205)	(51,205)			
Present Value (PV)	(451,016)	(310,114)	(307,616)	(325,336)			
Net Present Value (NPV)	**N/A**	**140,903**	**143,401**	**125,680**			
Internal Rate of Return (IRR) %	N/A	42.5%	45.5%	44.4%			
Discounted Payback (Yrs)	N/A	5.1	5.0	5.3			

Monte Carlo Simulation

The purpose of the analysis is to demonstrate the viability of Weld Overlay within the parameters of uncertainty that currently exist, before Stage 1 is complete. This was accomplished by completing a Monte Carlo simulation of the impact of Weld Overlay (versus Cut and Weld) using 28 variables that were identified as having the greatest impact on economic viability of the project.

Two Hundred Thousand (200,000) iterations were completed using @Risk software. The 28 variables were chosen randomly (for each iteration), within our best estimate of the parameters for each variable. The Monte Carlo analysis produced the following results:

Mean NPV = $72 Million
Maximum NPV = $233 Million
Minimum NPV = - $39 Million
There is a 90% confidence that the NPV will fall between $20 Million and $ 130 Million
The analysis produced 1,564 negative results
The analysis produced a tornado diagram ranking variable sensitivity. See below.



Refer to N-REP-30751-10007, "*Economic Analysis to Support Weld Overlay BCS N-BCS-30751-10002*" for detailed financial model assumptions used in the development of this business case.

Base Case: Not Recommended - Stop the project

This is not recommended, as the exclusive use of Cut and Weld tools will result in lengthy outages during the peak replacement years that could jeopardize the Darlington Business Plan and the Darlington target of 38-day outages.

Alt. 1: Recommended - Proceed with Stage II of the Weld Overlay project

It is recommended to proceed with the release of $53.2M Capital (including contingency) and $[redacted]M OM&A (specific contingency) to award and execute a contract for Stage II of the Weld Overlay project. This technology will provide an alternative feeder repair option for repairing thinned areas, with an expected reduction in:

- Overall time required to repair a feeder
- Execution cost of feeder repair
- Production and safety risks associated with breaking the pressure boundary (See Qualitative factors)

It is estimated that using Weld Overlay tools in conjunction with Cut and Weld tools (as required) starting in 2011 will provide a financial benefit of approximately $38M - $143M (NPV). At the conclusion of Stage I, an updated economic analysis will be prepared using vendor provided budgetary estimates for Stage II and a formal decision meeting will be held to determine whether to proceed with weld overlay tool development, therefore, limiting sunk costs should this project not prove beneficial.

This alternative includes a specific contingency of $[redacted]M capital to cover uncertainties regarding applicability of PST, as well as a specific contingency of $[redacted]M OM&A to deal with uncertainties regarding on-reactor commissioning in 2010.

Details of the proposal are presented in Section 4.

Alt. 2: Not Recommended - Delay project for 1 year

This alternative is not recommended because delaying the project will:

- Reduce the overall financial benefit by ~ $8M - $18M (NPV) if tooling is available for 2012 vs. 2011
- Increases the risk that, due to unforeseen issues in this R&D project, the tooling will not be ready when feeder repairs are most needed.
- Risk losing experienced team members and vendors to support tool development.

Alt. 3: Not Recommended - Include Pickering A and Pickering B

This is not recommended because:

- Pickering B has very few feeders that are candidates for weld overlay before end of life.
  Pickering A feeders may not benefit from grayloc-area overlay, as they have concerns with life-limiting thinning further downstream. The extent of downstream thinning and the potential benefit of grayloc-area overlay will become more apparent after further inspection programs are completed at Pick A. It would be advantageous to first develop the tooling for Darlington, and adapt the tooling for Pickering A later, as required.
- Both Pickering A and Pickering B have tighter clearances around the feeders, making tool design more challenging.

The NPV has not been shown for this alternative because of the uncertainty indicated above.

4/ THE PROPOSAL

Upon successful completion of Stage I (currently in-progress), a formal decision meeting will be conducted to determine whether to proceed with weld overlay tool development based on Stage I results and up to date Stage II budgetary estimates.

If tool development does not present a positive economic case or if Stage I was not able to resolve outstanding areas of technical risk, the project will likely be cancelled; otherwise, a revised BCS, within the value of this BCS, will be submitted for approval and used to award a contract for Stage II of the weld overlay tooling and processes development project for Darlington. Stage II will be executed in three (3) phases:

1. Detailed Design and Prototype Fabrication
   In this Phase, detailed documentation and drawings for the weld overlay tool and process will be prepared based on the parameters identified in Stage I.

   A prototype tool will be built and tested on a mock-up which will simulate real feeder configurations, feeder clearances and shutdown conditions.

   CNSC acceptance will be obtained for the weld overlay processes, analyses and inspections; as well as support for joint registration of the weld procedure with TSSA.

2. Fabrication and Mock-up Testing
   In this Phase, the Production Tools (up to [redacted] sets) will be manufactured and the application of the weld overlay and weld defect repair will be further tested and demonstrated.

3. Commissioning
   In this Phase, commissioning tests and available for service declaration will occur, with likely one commissioning trial at a Darlington unit in 2010.

5/ QUALITATIVE FACTORS

Using Weld overlay technology in combination with the Cut & Weld method (as required) potentially offers the following qualitative benefits:

- Eliminates the need for isolating, draining, removal and replacement of feeders experiencing thinning in the area adjacent to the Grayloc hub, thereby reducing production and safety areas of risk inherent in breaking the pressure boundary.
- Reduces exposure time, thereby achieving an overall reduction in radiation dose uptake.
- Reduces both the potential for loose contamination release and the production of high level active waste associated with Cut & Weld activities.

As well, this repair technology may be considered for providing a potential repair technique for pipe thinning problems in other systems or at other OPG stations.

6/ RISKS (see Attachment D for details)

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25		
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
The vendor's proposed cost of Stage 2 scope (Tool Design and Commissioning) is significantly higher than current estimates. Impact: Higher than estimated capital costs; lower NPV; delay to project resulting from the requirement for a superseding BCS approval.	▪ Conservative estimates based on Cut and Weld tooling development experiences have been used. ▪ A [redacted] % general contingency has been established for this project phase. ▪ A competitive atmosphere for award of Stage II has been set up with two vendors performing Stage I activities. ▪ A firm price contract will be negotiated.	12	15							15	6	8							8
The scope of work may increase based on unresolved technical issues, or discovery of new issues, or Regulatory requirements. Impact: Increased costs, schedule extension and increased complexity	▪ A [redacted] % general contingency has been established for this project phase. ▪ The proof of concept phase disclosed significant technical risks. ▪ Experienced vendors have been contracted.	16	20		8					20	6	15		6					15
The schedule necessary to meet the DNGD 2011 outage may not be achievable resulting in repair of feeders solely with cut and weld tooling during this outage. Impact: An estimated decreased	▪ Experienced vendors are being used. ▪ A competitive atmosphere between vendors has been established to increase their motivation. ▪ Capital funding release is being	20	25							25	16	20							20

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25		
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
savings of approximately $10M-$20M (NPV).	sought in order that Stage II award is not delayed.																		
Availability of long lead parts/tools (e.g. feeder mock-up) may delay tool development (Stage 2) and subsequent tool AFS resulting in repair of feeders solely with cut and weld tooling during the 2011 Darlington outage. Impact: An estimated decreased savings of approximately $10M - $20M (NPV).	▪ Plan to include Mock-up in vendor's deliverables for early Stage II. ▪ Use of existing mock-ups if available.	20	25							25	16	20							20
Lack of experienced OPG support resources for this project may lead to delays in reviews of deliverables or inadequate reviews. Impact: A delay in completion of this project due to schedule delays or due to rework.	▪ Appropriate engineering and project support resources will be identified and recruited to the project. ▪ Interface agreements will be obtained with required resource/interfacing teams. ▪ Managed task contracts will be set-up with external vendor experts.	8	16	12						16	6	9	6						9
Tool design and miniaturization may not be able to achieve all feeder configurations that will require repair. Impact: A continued need for cut and weld in inaccessible locations.	▪ The configurations with the most feeders to repair have been identified in the technical specification, and are the demonstration configurations in Stage I. ▪ The specification for the area of damage has been reduced	20								20	12								12

		Low = 1 to 3	Medium = 4 to 9	High = 10 to 25		
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Probability x Impact — Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation: Probability x Impact — Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
	by half since the proof of concept, thus reducing the overlay area required. ▪ Vendors will have to disclose known limitations at the end of Stage I so that this may be accounted for in the final economic evaluation before proceeding with Stage II.																		
The "As-Built" clearances at the grayloc area of some feeders may be more restrictive than the designed feeder clearances, resulting in the tooling not being able to fit those Weld Overlay feeder candidates. <u>Impact:</u> The cost of unplanned Cut and Weld repairs; Weld Overlay tool having less value than originally projected.	▪ A sample of actual field measurements will be performed during the spring 2009 DNGS outage to assess the magnitude of the difference. ▪ Actual field measurements of all candidate feeders will be recommended as they are available in lead-up outages to avoid unplanned replacement activities. ▪ Methods will be explored to increase feeder clearances, such as end-fitting jacking techniques.	20		16						20	12		9						12
Post Weld Overlay material properties (Residual Stress, Hydrogen Ingress and Hardness) may not be fully resolved after Stage I. <u>Impact:</u> Schedule delays and cost overrun for additional work	▪ Post Stage I decision meeting to cancel project if risk is too high going into Stage II. ▪ Removed DNGS feeders (artifacts) have been set aside for weld overlay testing purposes (if required).	15	15							15	6	6							6

Low = 1 to 3	Medium = 4 to 9	High = 10 to 25				
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation – Probability x Impact: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation – Probability x Impact: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
required. At worst, cancellation of the weld overlay project would result in sunk costs of approximately $16.5M OM&A (includes contingency) and any Stage II expenditures (Capital Release).	▪ Experienced vendors are being used.																		
Weld Overlay repair may not be feasible with fuel in the channel. <u>Impact</u>: Channel will be refueled for the weld overlay repair, increasing time and cost of the repair.	▪ Currently Cut and Weld requires the channel to be defueled therefore the cost of fuel would be the same under both Cut & Weld and Weld Overlay scenarios should this risk materialize. The cost of fuel has not been included in the economic analysis. (If included, the case for Weld Overlay is made stronger).	4								4	2								2
Regulatory approval sought in Stage II may be delayed or rejected. <u>Impact:</u> Schedule delays and cost overrun for additional work required. At worst, cancellation of the weld overlay project would result in sunk costs of approximately $16.5M OM&A (includes contingency) and any Stage II expenditures (Capital Release).	▪ A Regulatory plan has been prepared and an initial meeting held early in the project. ▪ During Stage I, at least one update meeting will be held with the CNSC ▪ Technical experts with knowledge in Code/Regulatory issues will be contracted for this work and will support Regulatory discussions and submissions. ▪ Nuclear Weld Overlay experience from utilities will be	12	15			9				15	6	8			4				8

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
		Impact			
	1	2	3	4	5
Probability 5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
	sought. ▪ Removed DNGS feeders (artifacts) have been set aside for weld overlay testing purposes (if required).																		
The Regulator may require a 48 hour wait prior to Ultrasonic Inspection of the overlaid area. This wait may be deemed necessary to allow crack initiation for hydrogen. <u>Impact:</u> The benefits of Weld Overlay will be reduced by the net additional time required for inspection.	▪ Stage I development includes significant effort to determine and minimize hydrogen ingress during weld overlay. Based on successful development in this area, the 48 hour period should not be required. ▪ Industry OPEX of weld overlay will be used to present a case that hydrogen induced cracking is not an issue.	16								16	12								12
The number of candidate weld overlay feeder repairs is reduced due to the approval of lower pipe thickness limits or adjustments to the rate of thinning calculations. Impact: Less return on investment. At worst, sunk costs could reach *$16.5M* OM&A (Including contingency) and any Stage II expenditures (Capital Release)	▪ Maintain communication with Feeder experts and stakeholders to quickly respond to changes in feeder condition or assessments. ▪ At the conclusion of Stage I, the economic benefits will be re-assessed prior to proceeding with Stage II; the minimum thickness limits will be reconfirmed at this time.	15								15	10								10
There may be a requirement for a Cut and Weld crew on standby as contingency during weld overlay. This standby charge	Supply chain to negotiate if required.	3								3	3								3

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
	Impact				
Probability	1	2	3	4	5
5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Probability x Impact – Before Mitigation									Probability x Impact – After Mitigation								
		Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
may be significant. Impact: Less return on investment.																			
The efficiency (time required) or the application cost per feeder of weld overlay is greater than that for cut and weld. Impact: Less return on investments. At worst, sunk costs could reach $16.5M OM&A (Including contingency) and any Stage II expenditures (Capital Release)	• At the conclusion of Stage I, the economic benefits will be re-assessed prior to proceeding with Stage II	8								8	8								8
The value of the Canadian dollar drops to a value for a sustained period of time that may significantly increase costs should a vendor from the U.S. be contracted for this job (<$0.8 USD). Impact: Higher cost of development and/or application	• Request proposals in Canadian funds. • 25% contingency has been added to conservative estimates.	12								12	6								6
The vendor's QA program is not approved for stage II work and/or implementation Impact: That vendor's bid is not acceptable.	• OPG Supply chain is engaged in reviewing and auditing the vendor's QA program. • Two vendors are contracted for stage I work.	8	15							15	8	10							10
Opportunity - Another utility with	• Senior Management to									4									8

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25		
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Probability x Impact									After Mitigation: Probability x Impact								
		Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
similar grayloc thinning issues may join OPG as a partner in the Weld Overlay Project. This would result in reduced weld overlay project costs by a significant amount.	continue discussions with interested utility.	4									8								
Opportunity – Process and tooling may be used for other Stations or systems.	•	9								9	9								9
Opportunity – Introduction of an alternate vendor for feeder repair may lead to more competitive quotes for future work.		6								6	6								6

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Comprehensive	Jun 2011	Dec 2012	VP Science & Technology Development

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Time to perform a single repair	Cut & Weld	<25 hours	Use outage reporting data	Performance Engineering
2.	Dose per repair	Cut & Weld	< cut and weld	mRem/Feeder Dose reporting system.	Reactor Maintenance
3.	Number of feeders that require cut and weld replacement per 100 feeders requiring repair.	Cut & Weld	< 10	Use outage reporting data	Major Components/ Feeders
4.	Weld overlay in-service repair failures.	N/A	0	SCRs	Major Components/ Feeders
5.	Number of pipe 'blow-thru' events	N/A	0	SCRs	Reactor Maintenance
6.	Cost per repair average.	Cut & Weld	< 500k in first 3 years	Negotiated cost per repair	Supply Chain

- A Comprehensive Post Implementation Review (CPIR) will be carried out at the conclusion of Stage 1 of the project to capture the lessons and make recommendations for the next stage. If a CPIR is found not appropriate at the end of Stage 1, it will be conducted within one year of the project in service (by December 2012), consistent with the corporate PIR Procedure.

- The Comprehensive PIR will be an independent and systematic performance evaluation of the project for these objectives:

  - Assess the realization of the project benefits consisting of:

    i. The effectiveness of the weld overlay repair technology in conjunction with Cut & Weld tooling over the previous cut and weld method alone

    ii. The measurement of project targets specified in the table above

- Review project intent, plan, implementation and operational performance
- Review BCS - major assumptions, economic and financial evaluation looking back from results, for future decisions
- Review project risk management
- Identify over all lessons learned, in addition to those documented by the project team, for future improvement

- The Comprehensive PIR will be conducted by Independent Team with the Team Leader appointed by the Project Approval Authority
- Key Lessons-Learned on the technology development, contracting and planning will be captured in addition to the project execution lessons.

Appendix "A" Glossary (acronyms, codes, technical terms)

- Acronyms etc are spelled out in the text.

Appendix "B" Project Funding History

$ 000's Capital Release Type	Month	All Existing and Planned Releases (incl contingency) Cumulative Values Year	2009	2010	2011	2012	2013	2014	2015	Later	Total
Full	May	2009	5,050	45,060	3,084						53,194
											0
											0
											0
											0
											0
											0
											0
LTD Spent	Feb	2009	0								0

$ 000's OM&A Release Type	Month	All Existing and Planned Releases (incl contingency) Cumulative Values Year	2005	2006	2007	2008	2009	2010	2011	Later	Total
Developmental	Feb	2005	200								200
Partial	Jun	2005	1,500								1,500
Partial	Jul	2006	1,273	686							1,959
Partial	Aug	2007	1,273	407	670	3,560					5,910
Partial	Oct	2008	1,273	407	497	3,867	10,490				16,534
Full	May	2009	1,273	407	497	3,867	10,490	1,000			17,534
											0
											0
LTD Spent	Feb	2009	1,273	407	497	1,470	260				3,907

Comments:

Appendix "C" Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	2%	SR & D Opportunity	Yes
Progress Payments	Yes	Foreign Currency	See Comments	Retainer Fee	No
Income Tax Rate	Generation	PST	See Comments	Interest Rate (Capital)	6%
Depreciation Rate (Capital)	Office, Misc Equipment 20%	Leasing	No	Indexed Priced Contract	No

Comments:

[redacted]% of tool development costs (~$[redacted]M) has been reserved in a specific contingency to cover uncertainties regarding applicability of PST which will not be resolved until the successful completion of Stage I.

Any Stage II foreign exchange issues will be covered by the 25% general contingency requested in this release.

Project Cost Estimate:

Design Complete	Zero to Minimal	Quality of Estimate	Conceptual + 60% to - 25%	3rd Party Estimate	Yes
Reviewed by Sponsor	Yes	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	Yes	Budgetary Quote(s)	No	First Unit Actual Used	N/A
Cost Sharing	No	Contracts in place	No	Competitive Bid	Yes
Fixed Price Contract	Yes	Fee for Service	No	Firm Vendor Proposal	No

Comments:

Refer to N-REP-30751-10007, "*Economic Analysis to Support Weld Overlay BCS N-BCS-30751-10002*" for detailed financial model assumptions used in the development of this business case.

Rationale for Cost Classification:

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)						
Pickering A	1	N/A	N/A	N/A	N/A							
	4	N/A	N/A									
Pickering B	5	N/A	N/A	N/A	N/A							
	6	N/A	N/A									
	7	N/A	N/A									
	8	N/A	N/A									
Darlington	1	Sep	2018	935	88%	D1111	D1411	D1711				
	2	May	2016			D1021	D1321					
	3	Mar	2020			D1231	D1531	D1831				
	4	Mar	2021			D1341	D1641					

Comments:

D1021 is included as target commissioning outage.

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Risk Informed Scenario

Impact on Revenue

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate KWH	58.36	52.98	54.58	54.58	56.23	56.23	57.93	57.93		
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Other	0.0	0.0	(8.6)	(23.0)	(3.0)	(23.7)	(34.2)	(22.0)	(151.5)	(266.0)
Base Case	**0.0**	**0.0**	(8.6)	(23.0)	(3.0)	(23.7)	(34.2)	(22.0)	(151.5)	(266.0)
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Other	0.0	0.0	(8.6)	(10.9)	(1.2)	(11.3)	(18.3)	(12.2)	(83.3)	(145.8)
Recommendation	**0.0**	**0.0**	(8.6)	(10.9)	(1.2)	(11.3)	(18.3)	(12.2)	(83.3)	(145.8)
Net Impact	**0.0**	**0.0**	**0.0**	**12.1**	**1.8**	**12.4**	**15.9**	**9.8**	**68.2**	**120.2**

Comments:

See NPV Calculations for Details and Summary

Impact on OM&A

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage OM&A	0.0	0.0	(2.7)	(11.7)	(1.8)	(13.1)	(25.9)	(10.7)	(104.8)	(170.7)
Project OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Case	**0.0**	**0.0**	(2.7)	(11.7)	(1.8)	(13.1)	(25.9)	(10.7)	(104.8)	(170.7)
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Outage OM&A	0.0	0.0	(2.7)	(7.4)	(1.3)	(8.6)	(16.0)	(6.9)	(65.2)	(108)
Project OM&A	0.0	(12.9)	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	(13.9)
Recommendation	**0.0**	(12.9)	(3.7)	(7.4)	(1.3)	(8.6)	(16.0)	(6.9)	(65.2)	(122.0)
Net Impact	**0.0**	(12.9)	(1.0)	**4.3**	**0.5**	**4.5**	**9.9**	**3.8**	**39.6**	**48.7**

Comments:

See NPV Calculations for Details and Summary

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Current Assessment Scenario

Impact on Revenue

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate KWH	58.36	52.98	54.58	54.58	56.23	56.23	57.93	57.93		
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Other	0.0	0.0	(17.3)	(43.1)	(17.8)	(53.2)	(151.4)	(61.0)	(230.0)	(573.8)
Base Case	**0.0**	**0.0**	(17.3)	(43.1)	(17.8)	(53.2)	(151.4)	(61.0)	(230.0)	(573.8)
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Other	0.0	0.0	(17.3)	(19.0)	(8.9)	(23.1)	(83.0)	(34.2)	(126.4)	(311.9)
Recommendation	**0.0**	**0.0**	(17.3)	(19.0)	(8.9)	(23.1)	(83.0)	(34.2)	(126.4)	(311.9)
Net Impact	**0.0**	**0.0**	**0.0**	**24.1**	**8.9**	**30.1**	**68.4**	**26.8**	**103.6**	**261.9**

Comments:

See NPV Calculations for Details and Summary

Impact on OM&A

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage OM&A	0.0	0.0	(10.6)	(23.5)	(7.4)	(29.1)	(101.5)	(37.1)	(161.6)	(370.8)
Project OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Case	**0.0**	**0.0**	(10.6)	(23.5)	(7.4)	(29.1)	(101.5)	(37.1)	(161.6)	(370.8)
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage OM&A	0.0	0.0	(10.6)	(14.6)	(4.9)	(17.8)	(62.9)	(23.3)	(101.4)	(235.5)
Project OM&A	0.0	(12.9)	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	(13.9)
Recommendation	**0.0**	(12.9)	(11.6)	(14.6)	(4.9)	(17.8)	(62.9)	(23.3)	(101.4)	(249.4)
Net Impact	**0.0**	(12.9)	(1.0)	**8.9**	**2.5**	**11.3**	**38.6**	**13.8**	**60.2**	**121.4**

Comments:

See NPV Calculations for Details and Summary

Weld Overlay Project 10 - 62568 Capital 10 - 62435 OM&A
Full Release Business Case Summary N - BCS - 30751 - 10002 – R000

Attachment "A"

Project Cost Summary

	$000's OM&A	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnt & Support									-
	Engineering									-
	Procurement									-
	Construction									-
	Other									-
	Project Management (OPG)	708	470							1,178
	Engineering & Drafting (OPG)	202	315							517
	Material	[redacted]								
	Contract - Other	[redacted]								
	Interest (Capital Project Only)									-
	Project Costs	[redacted]								
	General Contingency	[redacted]								
	Specific Contingency	[redacted]								
	Project Costs	3,647	12,887	1,000	-	-	-	-	-	17,534
Cash	Adjust to Cash Basis + / -	-	-	-					-	-
	Project Costs	3,647	12,887	1,000	-	-	-	-	-	17,534
Funding	Currently Released	3,647	12,887							16,534
	This Release			1,000						1,000
	Future Release								-	-
	Project Funding	3,647	12,887	1,000	-	-	-	-	-	17,534

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

		LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Budget	2009-2013 Business Plan	2,893	4,240							7,133
	Variance to Business Plan	754	6,423	-	-	-	-	-	-	7,177

		LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Other	Removal Costs included above									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

ONTARIOPOWER GENERATION

Weld Overlay Project 10 – 62435 OM&A
Full Release Business Case Summary N-BCS- 30751-10001-R000
Attachment "A"
Project Cost Summary

	$000's Capital	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnt & Support									-
	Engineering									-
	Procurement									-
	Construction									-
	Other									-
	Project Management (OPG)		166	507	166					839
	Engineering & Drafting (OPG)		108	108	108					324
	Material		[redacted]							
	Contract - Other		[redacted]							
	Interest (Capital Project Only)		46	1,183	760					1,989
	Project Costs	-	[redacted]							
	General Contingency		[redacted]							
	Specific Contingency		[redacted]							
	Project Costs	-	5,050	45,060	3,084	-	-	-	-	53,194
Cash	Adjust to Cash Basis + / -								-	-
	Project Costs	-	5,050	45,060	3,084	-	-	-	-	53,194
Funding	Currently Released									-
	This Release		4,995	43,905	3,060					51,960
	Future Release								1,234	1,234
	Project Funding	-	4,995	43,905	3,060	-	-	-	1,234	53,194

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

Budget	2009-2013 Business Plan		11,000	12,500	1,000					24,500
	Variance to Business Plan	-	(7,120)	21,948	1,387	-	-	-	-	16,215

Other	Removal Costs Included above									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

The estimated variance(s) to the 2009-2013 Business Plan will be addressed through the portfolio management process.
A PCRAF is not required .

Reviewed By:
Name
Carol Gregoris

April 15/09
Date:

Approved By:
Allan Lew
Eng & Mods Strat IV Manager

15 APR 2009
Date:

ONTARIOPOWER GENERATION

BUSINESS CASE SUMMARY

Project Name 10 - 62568 Capital 10 - 62435 OM&A

Full Release Business Case Summary N - BCS - 30751 - 10002 – R000

Attachment "B" — Project Variance Analysis

	Capital & OM&A	LTD Feb 2009	Total Project: Last BCS Oct 2008	Total Project: This BCS Feb 2009	Variance	Comments
Scores Basis	Project Mgmnt & Support				0	
	Engineering				0	
	Procurement				0	
	Construction				0	
	Other				0	
	Project Management (OPG)		2,095	2,017	-78	
	Engineering & Drafting (OPG)		626	841	215	
	Material		[redacted]			Mock-Up. Addt'l feeder samples
	Contract - Other		[redacted]			Addt'l costs for WO design, Qualification and commissioning.
	Interest (Capital Project Only)		1,000	1,989	989	
	Project Costs (Scores Basis)	**0**	**38,810**	**55,025**	**16,215**	
	General Contingency		[redacted]			
	Specific Contingency					PST Applicability, Commisioning
	Project Costs (Scores Basis)	**0**	**47,533**	**70,728**	**23,195**	

Other	**Removal Costs included above**	-	-	-	0	
	Inventory to be written off	-	-	-	0	
	Spare Parts In Inventory	-	-	-	0	

Comments:

Attachment "C" **Milestones and In Service Declarations**

Key Milestones

Completion Date			Description
Day	Mth	Yr	
30	09	2009	Award Stage II Contract
30	11	2010	Commissioning Complete
30	06	2011	AFS

A Project Execution Plan (PEP) **will be approved by Dec 2009**

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%
July	2011	In Service	40,500	100
Dec	2011	Project Closure	200	

Attachment D **Decision Map**

1. **Recommendation to CNO**
(Process to follow guidelines of Engineering Decision Making N-Guid-01900-10001; Type 3 Decision)

Purpose: To provide a recommendation of either proceeding with Stage II, or canceling the project based on the technical results of Stage I and an updated economic analysis for Stage II. This recommendation will be documented and presented to the CNO, for acceptance.

Chair/Sponsor: Paul Spekkens, VP Science & Technology Development

Attendees:

(1) CNE *
(2) Darlington Director of Engineering *
(3) At least one other Station Engineering Director * (Contrarian Role)
(4) Senior Manager Plant Design Darlington *
(5) Director Engineering Services *
(6) Manager Feeder Integrity Project
(7) Manager Performance Engineering Darlington
(8) Director Nuclear Finance
(9) Manager Nuclear Finance
(10) Manager Darlington Maintenance
(11) Weld Overlay Team Representatives

Format:

Presentation:

- Project Team to present the results of Stage I and an updated risk table based on these results.
- Project Team to present an assessment of the regulatory risk.
- Project Team/Nuclear Finance to present an updated economic analysis incorporating updated:
  1. Costs (vendor proposal in-hand),
  2. Schedule, and
  3. Assumptions.
     - Feeder repair numbers (based on Spring 2009 inspections)
     - Tool limitations (based on clearances vs. conceptual design)
     - Time to apply repair (estimated)
     - Cost of application (budgetary)
     - Monte Carlo analysis results
  4. Other alternatives considered (including lower minimum thickness requirements)

Discussion:
Open discussion and questions

Decision:
CNE makes the decision. Dissenting opinions are to be noted.

Criteria for a decision to proceed should include the following:

- Revised BCS updated economic analysis continues to have a positive NPV.
- Technical risks low; limited medium technical risks may be accepted.
- Regulatory Risk low.

Minutes:

- Presentations, major discussion items, decision, and dissenting opinions are to be recorded.
- Actions with dates should be captured and A/Rs created as appropriate.

- The Recommendation is to be documented and the revised BCS presented for signature by the CNE.

2. CNO acceptance meeting

- CNO acceptance or rejection of the recommendation is to be documented and the revised BCS presented for signature.
- Attendees: CNE
  VP Science & Technology Dev (Project Sponsor)
  SVP Darlington (or delegate)
  Director Station Engineering, Darlington
  VP Nuclear Finance
  Manager, Feeder Integrity Projects
  Project Manager – Weld Overlay Project

- Any actions should be captured and A/Rs created as appropriate
- CNO to take the recommendation and revised BCS to the COO for approval.

3. COO acceptance meeting

- COO acceptance or rejection of the recommendation is to be documented and the revised BCS presented for signature.
- Attendees: CNO
  CNE
  VP Science & Technology Dev (Project Sponsor)
  SVP Darlington (or delegate)
  VP Corporate Investment Planning

4. President Approval of Revised BCS

Attachment "E"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 [illegible])	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges OR Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages OR Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

Upper Feeder Cabinet Inspection Robot 10 - 66266

Full Release (Phase 1) Business Case Summary N-BCS-30674-10005-R000

1/ RECOMMENDATION:

We recommend approval of the Full Release Phase 1 for 5168 k$ (including contingency) [LTD – 6168 k$] to allow IMS to complete Phase 1 of the Upper Feeder Cabinet Inspection Robot Project. Phase 1 consists of procuring, commissioning, and making available for service, one system for use at Pickering A & B.

The overall objective of this project is to develop remotely operated robotic tooling that can be used in the Pickering, Darlington and Bruce Power upper feeder cabinets to remotely perform visual inspections in the feeder cabinets as specified by their respective engineering groups. The objective is driven by the following:

1. With current technology, there is an inability to access all the required inspection areas due to obstructions and limitation to human dexterity.
2. Scope currently set based on existing technology, knowing that some areas are inaccessible, as well as on other outage constraints limiting access to feeder cabinets.
3. Going forward (after 2009), this work will impact on critical path due to feeder freezing (confined space) and improvements in reactor face feeder inspection. The impact could be as much as 8 days.
4. This is dose-intensive work, with a typical inspection campaign consuming approximately 5 Rem.
5. IMS is finding it difficult to obtain the resources needed to conduct dose-intensive inspections.

The initial release amount of $1000K focused on Pickering feeder cabinets only. Spending to date on the project has focussed on clarifying the need, developing the design requirements, engaging vendors and developing a better estimate of the project cost. This BCS provides a budget quality estimate based on the completed design requirements and input from vendors. In order to mitigate the risks associated with investment in new technology, a phased approach is recommended for further releases of funds.

Release of funds for this phase will deliver one complete inspection system for Pickering, as well as the following:

- A set of critical spares to be available for the first campaign at each site.
- Initial training of personnel operating the equipment.
- Equipment operating manual and/or procedures.
- Design and testing documentation as required by the ETCC process.
- Technical support during the first outage at each site in which the equipment is used.

Robot Design Requirements are described in "Pickering Feeder Cabinet Remote Visual Inspection Robot" I-DR-30674-50000-R000. Separate Design requirements will be written for Darlington and Bruce Power during phase 1 of the project.

Execution of inspection campaigns is not part of this project, nor is modifications to any station systems or components.

The capital expenditure for this project will support ALARA initiatives, reduce future impact on critical path activities, and improve the quality of inspections at both OPG and Bruce Power. Once an agreement is in place with Bruce Power, this investment will also provide labour and equipment rental revenues.

The financial evaluation for the recommended alternative indicates that this project will enhance value by $15.7M over a 10-year time period, while phase 1 alone will enhance value by $6.9M over the same period.

Table 1: Funding Summary

Choose One	Funding	LTD 2007	2008	2009	2010			Later	Total
Currently Released	Developmental	1,000							**1,000**
Requested Now	Full - Phase 1	(630)	2,541	3,257					**5,168**
Future Funding Req'd	Full - Phase 2				5,238				**5,238**
Total Project Costs		**370**	**2,541**	**3,257**	**5,238**	**-**	**-**	**-**	**11,406**
Other Costs									**-**
Ongoing Costs									**-**
Grand Total		**370**	**2,541**	**3,257**	**5,238**	**-**	**-**	**-**	**11,406**
Investment Type Value Enhancing		**Class Capital**		**(IEV) Impact on Ec Value Phase 1+2: $15.7M**		**IRR NA**		**Discounted Payback NA**	

Submitted By:

R.C. Morrison Date:
Vice President, Inspection & Maintenance Services

Finance Approval:

Jim Beech Date:
Vice President, Nuclear Finance

Line Approval (Per OAR Element 1.1 Project in Budget):

P. R. Charlebois Date:
EVP & Chief Operating Officer, OPGN

Table 1: Funding Summary

Choose One [illegible]	Funding	LTD 2007	2008	2009	2010	[illegible]	[illegible]	Later	Total
Currently Released	Developmental	1,000							1,000
Requested Now	Full - Phase 1	(630)	2,541	3,257	-				5,168
Future Funding Req'd	Full - Phase 2				5,238				5,238
Total Project Costs		**370**	**2,541**	**3,257**	**5,238**	**-**	**-**	**-**	**11,406**
Other Costs									-
Ongoing Costs									-
Grand Total		**370**	**2,541**	**3,257**	**5,238**	**-**	**-**	**-**	**11,406**
Investment Type: Value Enhancing			Class: Capital		EV Impact on Ec Value: Phases 1 2 $15.7M		IRR: NA	Discounted Payback: NA	

Submitted By:

RCMorrison 17 Jan 08

R.C. Morrison
Vice President, Inspection & Maintenance Services
Date:

Finance Approval:

Jan 24 2008

Jim Beech
Vice President, Nuclear Finance
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Feb 5/08.

P. R. Charlebois
EVP & Chief Operating Officer, OPGN
Date:

2/ BACKGROUND & ISSUES

A prior release for this project was obtained for $1000K, to provide a solution for Pickering only. At that time, the unique challenges posed by the confined spaces in the Upper Feeder Cabinet were not recognized, and it was assumed that a predominantly off-the-shelf solution would be possible. However, after preparing the design requirements, and obtaining proposals it was recognized that the required hardware would be significantly more expensive to design and fabricate. Furthermore, there is also a need for similar systems at both Darlington and Bruce Power. This BCS release provides the necessary funding and justification to complete the project.

The inspection of feeder/supports forms part of OPG's "PHT Feeder Piping Aging Management Strategy And Plan", N-PLAN-01060-10001. Moreover, it is one of OPG's commitments to the CNSC. From the above perspective, the priority of this project is high. From a safety perspective, there is no near-term safety threat emanating from potential failure of feeders or their supports. However, a failure of one feeder would require the unit to be shut-down to disposition, and to determine whether a repair is possible. Then, because of the potential that a similar failure could take place in another unit, and the lack of recent inspection data to indicate otherwise, it may result in the near-immediate shut-down of all similar operable units until all are inspected. Even if there is no failure there is an ongoing need to get more data to demonstrate feeder/support fitness-for-service. The same drivers exist at Bruce Power.

Feeder cabinet inspections performed in the traditional direct visual manner require a rotation of inspection technicians to accommodate the high radiation exposure. Exposure limits, and staff availability are currently challenging IMS's ability to complete these inspections.

IMS has determined that going forward (after 2009), this work will impact on critical path due to feeder freezing during feeder replacements (confined space) and due to improvements in productivity on the reactor face feeder inspections. The impact could be as much as 8 days, depending on site. With a robot that impact is expected to be reduced by 75%.

At this time there is no commercially available robotic tool that can do this specific job, thus the need to develop a remotely operated tool that can reach into the confined spaces between feeder rows in the feeder cabinet.

The impacts of not proceeding with this project would be:

- Continuing to inspect at Pickering and Darlington using manual methods. This incurs high radiation exposure, and leaves some items uninspected, or partially inspected.
- Lost opportunity for revenue from this service from Bruce Power.
- Impact on critical path once large volume feeder replacements start.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

The key assumptions for this financial analysis are listed in Appendix C.

The alternatives described below are evaluated over a time period of 10 years, from 2008 to 2017. The most significant cost of this project is the robot – expected to exceed ~$4000K for the first one, and ~$2000K for subsequent robots. This cost, combined with the cost of mockups, account for approximately 90% of total project cost.

Phase 1 economic analysis is summarized in Table 2.

Table 2: Phase 1 Financial Summary

Choose One	Status Quo	Alt 1 (Recommended)		Alt 2 Delay	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost				
Revenue							
OM&A	(33,334)	(11,111)	(11,111)				
Capital		(6,170)	(5,800)				
NPV (after tax)	(17,102)	(10,181)	(10,181)				
Impact on Economic Value (IEV)	N/A	6,921	6,921				
IRR%	N/A	N/A	N/A				
Discounted Payback (Yrs)	N/A	N/A	4				

The economic analysis for the entire project is summarized in Table 3. As indicated in Table 3, the best economic value over the base case comes from funding three systems, and recovering some of the costs from rental to Bruce Power.

Table 3: Full Project Financial Summary

Choose One	Status Quo	Alt 1 (Recommended)		Alt 2 Delay	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost				
Revenue		20,139	20,139	Not		13,396	
OM&A	(48,387)	(19,877)	(19,877)	Evaluated	(16,437)	(24,627)	
Capital		(11,410)	(11,040)		(8,270)	(6,670)	
NPV (after tax)	(24,274)	(8,563)	(8,563)		(14,147)	(10,644)	
Impact on Economic Value (IEV)	N/A	15,711	15,711		10,127	13,630	
IRR%	N/A	N/A	N/A		N/A	N/A	
Discounted Payback (Yrs)	N/A	4	4		4	3	

Status Quo - Not Recommended

Doing nothing or stopping the project will result in the inability of IMS to supply sufficient data for station fitness-for-service analyses, increased resource usage, and increased radiation exposure. If OPG cannot satisfy the regulator that the upper feeder cabinet components are fit for service, unit shut-down would be required.

Going forward (after 2009), this work will impact on critical path due to feeder freezing (confined space) during replacements, and due to improvements in reactor face feeder inspection productivity.

There is a high demand for nuclear workers in Ontario, and it is increasingly difficult to staff feeder inspection campaigns. Furthermore, this decision would go against initiatives for ALARA exposure and employee engagement.

Alternative 1 - Develop new tooling and supply services to both OPG & Bruce Power, in two phases (IEV: $15.7M) - Recommended

Phase 1:

This first phase of this alternative is focused on providing a solution for Pickering A and B. Design requirements have been prepared and proposals have already been received. Pickering A and B also have the most challenging configurations in the feeder cabinets. Future changes to scope of inspections, and changes to end-of-life predictions (especially at Pickering) have not been considered for this phase 1 release, since no solid evidence exists for such changes, and because to financial evaluation relies on known and comparable scopes. Phase 1 provides an improved NPV of $6.9M over the base case, for Pickering A and B only.

The capital expenditure for this project will support ALARA initiatives, minimize the impact on critical path, and improve the quality of inspections.

Phase 2:

In Phase 2, this alternative will provide a system for Darlington, and new revenues from Bruce Power.

Combined, the two phases provide an improved NPV of $15.7M over the base case. The risk with this alternative is higher than others due to the high capital outlay, and the dependence on revenues from Bruce Power until at least 2014. However it is possible that revenues from Bruce Power could increase as all eight units at that site become operational. This alternative provides the best return on investment. Under this alternative, three systems would be built to meet the minimum needs of each site.

Alternative 2 - Delay Project - Not Recommended

Not evaluated.

Alternative 3 – Project for Pickering and Darlington Only (IEV: $9.6M) - Not Recommended

Phase 2:
This alternative is viable should IMS decide not to pursue the feeder cabinet inspection work with Bruce Power. Two systems would be built, one for Pickering and one for Darlington. The systems would not be interchangeable because of differences in design between the two sites. While Pickering has a larger inspection scope than Darlington, operational experience indicate that it would be possible to manage the current scope with two systems. Should there be and increase in scope in the future, a separate evaluation would be done to justify purchasing additional systems.

Alternative 4 – Jointly Funded Project between OPG & Bruce Power (IEV: $13M) - Not Recommended

Phase 2:
This alternative is similar to alternative 1 in the equipment and service being provided. It will also be phased similarly. However, Bruce Power will share in the cost of the project and own one system. IMS will operate and maintain that system. This alternative results in reduced risk for OPG, but also reduces revenue.

Alternative 5 – - Not Recommended

N/A

4/ THE PROPOSAL

Phase 1:

It is proposed that one inspection system be purchased and placed in service to support inspections at Pickering, A and B. This phase of the project will provide a fully remotely operated inspection solution making access to feeders/supports beyond the reach of hand held video probes more practical and will also reduce personnel dose at Pickering. It encompasses design, fabrication and commissioning of a robot for visual inspections of feeders and structures in the upper cabinet. Visual inspections include, but are not limited to, chafing shield and feeder hangar inspections, including those that have been impractical to date given the hand held tooling and the configuration of the feeders.

This phase, for which an additional $5800K is being requested now, will be used to place the first system in service at Pickering A and B, and to do the preliminary engineering work for Darlington and Bruce Power. The target outage for this phase is P911 scheduled for September 2009.

The two primary concepts being considered are illustrated in Figures 1 and 2. These concepts were developed for Pickering and show the arm reaching under the catwalk. At Darlington, Bruce A, and Bruce B the paths of the arm would be more direct, and as such the solution could be made less complex.

These concepts take into consideration the experience gathered from past attempts at Pickering (in 1991), and at Bruce Power (in 2006) to introduce remote inspection capability. The robotic inspection system would be able to carry the necessary visual inspection equipment and access feeder supports or components previously inaccessible. This will be done with efficiency at least equal to current inspection times (on equivalent scope), and provide improved inspection quality.

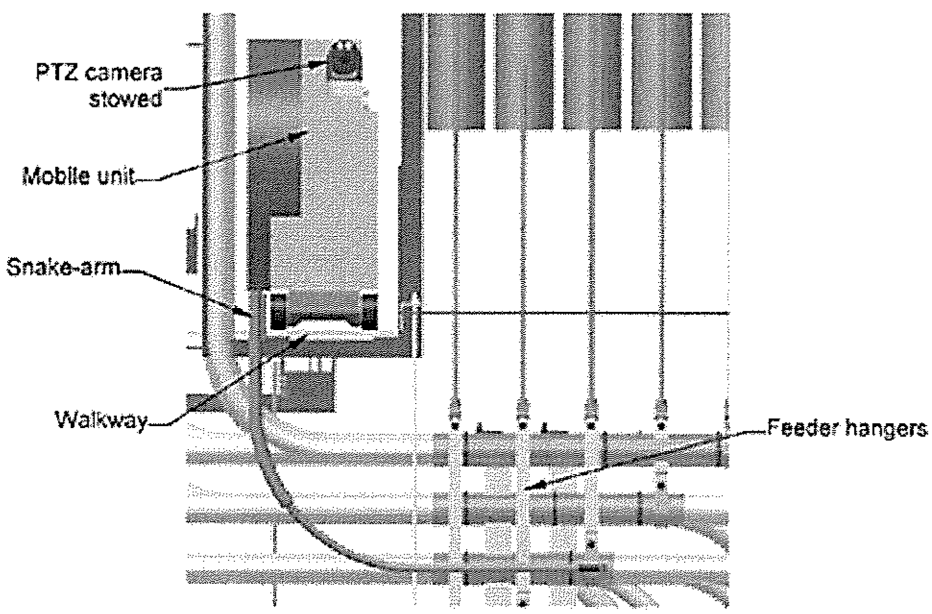


Figure 1: Snake Arm Concept.

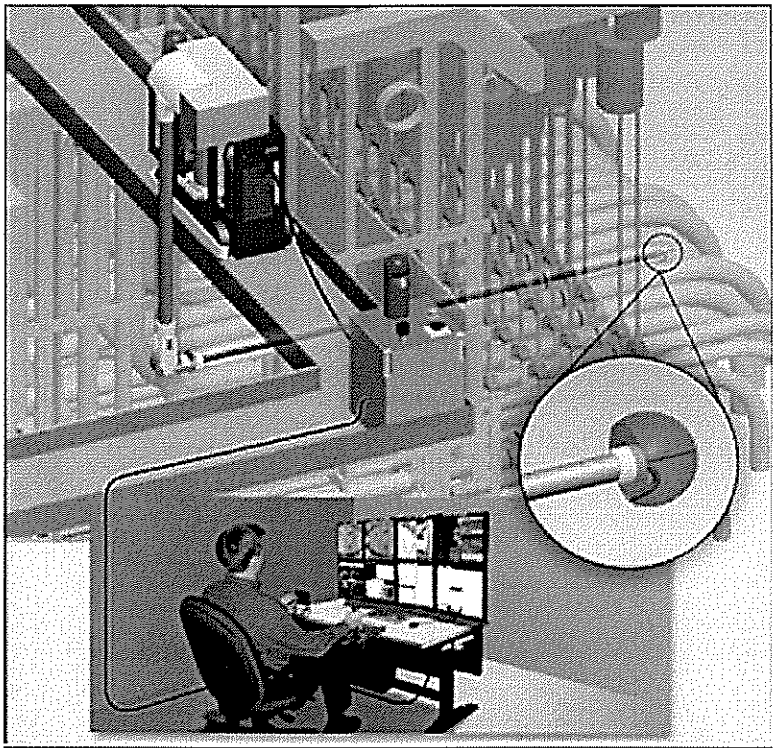


Figure 2: Collapsible Boom Concept.

Key milestones are presented in Attachment C. In general is governed by the following:

It is estimated that it will take approximately 15 months to create and commission the first inspection robot and mockup, and two to three months to train personnel and prepare procedures to perform the inspections. The project will be fully prepared for the first inspection campaign within approximately 18 months of award of a Purchase Order.

Phase 2:

A subsequent release will be sought for two additional systems – for Darlington and Bruce Power. The systems will be unique to Darlington and Bruce Power reactors. No work will be initiated for Bruce Power until specific project and service agreements are in place with Bruce Power. Required funding for Phase 2 is expected to be $5240K.

5/ QUALITATIVE FACTORS

- ALARA initiatives: This project would support radiation exposure reduction (ALARA) initiatives at both OPG and Bruce Power.
- Quality of Inspections: There will be improvements in the quality of inspections, with more areas accessible, and with better recording of data.
- Revenue growth: The tool may have marketing potential out of province and out of the country. Additional robots would be procured once contracts are in place with other utilities.
- Expanded usage: There is the potential to adapt this technology to inspect other areas of the plants.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Internal funding and approval delays have caused the validity of proposals to expire.	Vendors may request the right to re-quote their proposals at a higher cost.	**Medium**	Proposals came in over a wide price spectrum, with the leading proposal significantly lower than the estimate in this BCS. Vendors will be asked to extend the validity of proposals. If necessary, the RFP process will be repeated.	**Low**
This is a new application of new and complex technology. Engineering Change Control could require studies, approvals, and modifications not previouly considered.	Increase in cost. Extension of schedule	**High**	A Modification Outline will be prepared that encompasses the experience from other robotics projects within IMS. Site stakeholder input will be sought. This cost will be priced in as an ECC risk mitigation amount.	**Low**
Scope				
Scope Changes	Scope will increase due to requests for additional enhancements	**Medium**	Initial scope has been defined in the Design Requirements for Pickering. Darlington and Bruce scope will be defined in DR's as well.	**Low**
Schedule				
Delays to project start due to internal approvals	Continued use of manual methods for inspections, associated with high dose.	**High**	The schedule is highly dependent on internal OPG approvals. Project management oversight and control will be enforced. Support at the appropriate level will be sought.	**Medium**
Selected Vendor unable to deliver robot as per agreed schedule	Increase in cost. Extension of schedule	**High**	Vendor ability to meet schedule is included as part of the vendor evaluation criteria. Surveillance of vendor workload and resources would be performed.	**Low**

Resources				
Insufficient resources during any phase will affect the schedule. In particular, securing resources required from IMS at the beginning of the contracts, and during training and commissioning is risky.	Lack of resources will result in increased OT cost, and/or a schedule extension.	**Medium**	A commitment to supply technical and contract management staff for the early phases will be obtained from stakeholders in IMS Engineering, Supply Chain, and IMS Projects. This will be priced in as a labour risk mitigation amount.	**Low**
Technical				
Robot is unable to provide the quality of inspections in terms of access to required components, and quality of images.	No improvement in inspection quality	**Medium**	Prototype testing and acceptance tests will confirm robot performance. PO for 2nd and 3rd robots will be contingent on success of 1st.	**Low**
Unplanned site modifications are required	If mods to site structures are required, such as temporary installation of tracks on the catwalks, the cost would increase.	**Medium**	This will be priced in as a site risk mitigation amount. The design requirements will be written to preclude site mods.	**Low**
Regulatory				
Regulator accepts a much reduced scope of inspections.	The impact on critical path would be reduced or eliminated. Dose uptake would be reduced.	**Medium**	There would still be a need to perform inspections. Current experience indicates that scope is set based on available technology. The better the technology, the higher the demand for information. Other applications can be found for the system.	**Medium**
Environmental				
Failure of equipment, tools, components to operate in a radiation tolerant environment.	Robot efficiency does not meet the stated goals and outage extension is required, or higher dose received.	**Medium**	Requirement to operate in a radiation tolerant environment and selection in components, materials, etc. that are not susceptible to radiation shall be a design condition and documented in both design requirements and technical specifications. Prior OPEX being incorporated in the Design	**Low**

			Requirements.	
Health & Safety				
Radiation exposure reduction is not achieved.	Station health and safety performance targets are not met.	**Medium**	A mockup will be built and comprehensive testing and commissionning will be performed prior to placing system in service.	**Low**
Investment				
Bruce Power does not agree to purchase the service for the duration required	Project cost will not be recovered.	**High**	A contract will be established with Bruce Power prior to initiating any work for Bruce Power. This BCS indicates that there is still a benefit to implementing the solution for OPG only.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Sep 2009	Mar 2010	Manager, IMS Balance of Plant & Feeders Department

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Quality of Inspections: Access to most difficult-to-reach area.	At Pickering, there is no access to Row 36, "A" clevis, North side, the 4th and 5th feeders down.	This area accessible and visual inspection record (image) created.	Review of Inspection reports.	RC&S; Eng and Mods, with input from IMS.
2.	Scope reduction due to exposure control limits.	Scope is identified in the Inspection Specifications. Some scope reduction typically identified in the Inspection Reports due to fields or dose uptake.	No Scope reduction due to exposure control limits.	Review of Inspection reports.	IMS Engineering
3.	Personnel Exposure	5 Rem per campaign, based on current inspection scope.	1 Rem per campaign, for equivalent inspection scope.	Radiation Information System, and Unit-specific outage scope of work.	FLM &/or Workgroup supervisor
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

ALARA: As Low As Reasonably Achievable

BCS: Business Case Summary

CANDU: CANada Deuterium Uranium

DR: Design Requirement

ETCC: Engineered Tool Change Control

FME: Foreign Material Exclusion

IMS: Inspection and Maintenance Services

IEV: Impact of economic Value

NDE: Non-Destructive Examination

NPV: Net Present Value

OPG: Ontario Power Generation

PEP: Project Execution Plan.

RB: Reactor Building

TMB: Training and Mockup Building.

Appendix "B" Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency)									
				Cumulative Values							
Release Type	Month	Year	2006	2007	2008	2009	2010	2011	2012	Later	Total
Developmental	Jun	2,006		1,000							1,000
Full (Phase 1)	Dec	2,007		370	2,541	3,257					6,168
Full (Phase 2)	Apr	2,009		370	2,541	3,257	5,238				11,406
											0
											0
											0
											0
											0

LTD Spent	Nov	2,007		370							370

Comments:

Appendix "C"

Financial Model – Assumptions

Project Cost Assumptions:

1. Major costs: 1st robot $4.2M; subsequent: $2M; mockups: $500K each
2. Contingency: 10%
3. Due to the nature of this project Risk mitigation funds have been included separate from contingency. Risk mitigation total is $170K
4. Average Labour cost is $75/hr. This is a blended rate that includes OT and contract labour costs.
5. Project Cost does not include inspection execution. Those costs will be billed to sites separately.
6. If Bruce Power co-funds the project (Alternative 4) There will be project revenue of $5.5M

Financial Assumptions:

7. Capital expenditure is Class 8.
8. Interest on capital is 5.9%.
9. Discount rate is 7%.

Project / Station End of Life Assumptions:

10. Project will be executed in 2 phases. Phase 1 will be completed in 2009. Phase 2 will be complete in 2010.
11. It is expected that the robot systems would last for at least ten years. The cost of on-going maintenance and modifications are included in the campaign costs.
12. Darlington will be on a 3-year outage schedule.
13. The last Pickering B outage will be in 2014.

Energy Price / Production Assumptions:

14. Going forward (after 2009), this work will impact on critical path due to feeder freezing (confined space) and improvements in reactor face feeder inspection. While this impact could be as much as 8 days, it is conservatively assumed that the impact would be 1 to 3 days, depending on site. With a robot that impact is assumed to be reduced by 75%.
15. SEV: $49.5/MWhr. PNGS- 515 MW/unit; DNGS: 878MW/unit.

Operating Cost Assumptions:

16. Operating costs include maintenance, consumables, training, documentation, and inspection execution.
17. With the robot, execution labour costs will reduce by approximately 60%, while maintenance/mobilization costs will increase by approximately 45%.
18. For the purposes of the financial evaluation of alternatives, it is assumed that future scope of inspections is similar to the current scope.

For Bruce Power, operating revenue assumptions are:

19. There is no current inspection scope with Bruce Power. It is assumed the scope would be inspection of all critical components in one feeder cabinet. This is significantly more that is currently being achieved by Bruce Power personnel.
20. Rental at Bruce Power is $[redacted]per outage, if OPG owns the robot.
21. There will be reduced maintenance & mobilization charges to Bruce Power if they are paying rental.
22. There will be[redacted]campaigns a year at Bruce Power, starting in 2010.

23. Average price of labour charged to Bruce Power is cost x [redacted] This is estimated to be $[redacted] in 2010, and will increase at [redacted] per year subsequently.

<u>Other Assumptions:</u>

24. Cost per Rem: $25K
25. Resources will be available to execute project as per schedule.
26. The level 1 schedule dates assumes that funding is released before December 20, 2007.

ONTARIOPOWER GENERATION

Upper Feeder Cabinet Inspection Robot 10 - 66266

Full Release (Phase 1) Business Case Summary N-BCS-30674-10005-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2007	This Release 2008	This Release 2009	Future Release 2010				Later	Total
Project Management (OPG)	60	70	22	28					180
Engineering & Drafting (OPG)	180	157	15	71					423
Material									-
Installation – PWU, BTU									-
Contract - Design	35	[redacted]							
Contract - Installation									-
Contract - Other	85	[redacted]							
Cost Risk Mitigation		[redacted]							
Site Risk Mitigation		[redacted]							
Interest (Capital Project Only)	10	93	123	232					458
Project Costs (excl contingency)	**370**	[redacted]							
General Contingency		[redacted]							
Specific Contingency									-
Project Costs (incl contingency)	**370**	**2,541**	**3,257**	**5,238**	**-**	**-**	**-**	**-**	**11,406**
2008-2012 Business Plan		2,481	2,481						4,962
Variance to Business Plan	**370**	**60**	**239**	**4,783**	**-**	**-**	**-**	**-**	**5,451**
Committed Cost									-
Inventory Write Off Required	-	-	-	-					-
Spare Parts / Inventory									-
Total Release (excl contingency)	**370**	[redacted]							
Total Release (incl contingency)	**370**	**2,541**	**3,257**	**5,238**	**-**	**-**	**-**	**-**	**11,406**

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	Up to ~ 15%		Quality of Estimate	Budget + 30% to - 15%	
3rd Party Estimate	N/A	OPEX used	Yes	Lessons Learned	N/A
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2008-2012 Business Plan will be addressed through the portfolio management process. A PCRAF is not required .

Reviewed By:

Tulchand Harduwar
Project Manager
Date:

Approved By:

Don Jarron
Eng & Mods Manager (Strat IV)
Date:

Upper Feeder Cabinet Inspection Robot 10 - 66266

Full Release (Phase 1) Business Case Summary N-BCS-30674-10005-R000

Attachment "A" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2007	This Release 2008	This Release 2009	Future Release 2010				Later	Total
Project Management (OPG)	60	70	22	28					180
Engineering & Drafting (OPG)	180	157	15	71					423
Material									-
Installation – PWU, BTU									-
Contract - Design	35	[redacted]							
Contract - Installation									-
Contract - Other	85	[redacted]							
Cost Risk Mitigation	[redacted]								
Site Risk Mitigation	[redacted]								
Interest (Capital Project Only)	10	93	123	232					458
Project Costs (excl contingency)	370	[redacted]							
General Contingency	[redacted]								
Specific Contingency									-
Project Costs (incl contingency)	370	2,541	3,257	5,238	-	-	-	-	11,406
2008-2012 Business Plan		2,481	2,481						4,962
Variance to Business Plan	370	60	239	4,743	-	-	-	-	6,451
Committed Cost									-
Inventory Write Off Required	-	-	-	-					-
Spare Parts / Inventory									-
Total Release (excl contingency)	370	[redacted]							
Total Release (incl contingency)	370	2,541	3,257	5,238	-	-	-	-	11,406

Ongoing OM&A (per project)									
Removal Costs (incl in above)									

Basis of Estimate					
Design Complete	Up to ~ 15%		Quality of Estimate	Budget + 30% to - 15%	
3rd Party Estimate	N/A	OPEX used	Yes	Lessons Learned	N/A
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2008-2012 Business Plan will be addressed through the portfolio management process. A PCRAF is not required

Reviewed By:

Tulchand Harduwar
Project Manager

Jan 2008
Date:

Approved By:

Don Jarron
Eng & Mods Manager (Strat IV)

25 JAN 2008
Date

Upper Feeder Cabinet Inspection Robot 10 - 66266

Full Release (Phase 1) Business Case Summary N-BCS-30674-10005-R000

Attachment "B" **Project Variance Analysis**

Capital	LTD Oct 2007	Choose One Last BCS Jun 2006	 This BCS Dec 2007	Variance	Comments
Project Management (OPG)	60	80	92	12	
Engineering & Drafting (OPG)	180	40	172	132	ECC, Feeder Cabinet & Mockup modelling
Material				0	
Installation – PWU, BTU				0	
Contract - Design	35	[redacted]			Significantly higher robot cost in this BCS
Contract - Installation		[redacted]			
Contract - Other	85	[redacted]			Supply chain support included
Cost Risk Mitigation		[redacted]			
Site Risk Mitigation		[redacted]			
Interest (Capital Project Only)	10	30	216	186	
Project Costs (excl contingency)	**370**	[redacted]			
General Contingency		[redacted]			
Specific Contingency				0	
Project Costs (incl contingency)	**370**	**1000**	**5799**	**4799**	
Committed Cost				0	
Inventory Write Off Required	0	0	0	0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**370**	**1000**	**5799**	**4799**	
Total Release (excl contingency)	**370**	[redacted]			

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

Attachment "C" Key Milestones

Completion Date			Description
Day	Mth	Yr	
31	Mar	06	F466266001 Project Charter Approved
17	May	06	F466266005 Full Release BCS Approved
16	Mar	07	F466266009 Design Requirements Issued
15	Jun	07	F466266033 Issue PEP
30	Nov	07	F466266043 Phase 1 BCS Approved
28	Feb	08	F466266025 Major Equipment PO's In Place
28	May	09	F466266029 Initial Equipment Testing complete
22	Jul	09	F466266017 Training Program Available
22	Jul	09	F466266021 Operating / Mtce Procedures available
28	Aug	09	F466266013 First System Ready For Service (P911)
30	Jul	09	Phase 2 BCS Approved
30	Sep	09	Phase 2Major Equipment PO's In Place
30	Aug	10	Other Systems Ready For Service

A Project Execution Plan (PEP) was approved in Jun 2007

Comments:
A revised BCS will be prepared for Phase 2.